ESCAMBIA OPERATING COMPANY, LLC
BIG ESCAMBIA CREEK OIL & GAS PRODUCTION, TREATING & PROCESSING FACILITY
FACILITY NO.: 502-0007
ATMORE, ESCAMBIA COUNTY, AL

STATEMENT OF BASIS

The proposed Title V Major Source Operating Permit (MSOP) second renewal is issued under the provisions of ADEM Admin. Code R. 335-3-16. The above named applicant has requested authorization to perform the work or operate the facility shown on the application and drawings, plans, and other documents attached hereto or on file with the Air Division of Alabama Department of Environmental Management, in accordance with the terms and conditions of this permit.

Vintage Petroleum, Inc. was issued the existing MSOP on July 6, 2006, with expiration date of January 7, 2011, for the Big Escambia Creek Oil and Gas Production, Treating and Processing Facility (BEC Plant) located at 3888 Sardis Church Road, Atmore, Escambia County, AL. On June 1, 2006, the BEC Plant was acquired by Escambia Operating Company, LLC (EOC) (a subsidiary of Eagle Rock Energy) and on December 10, 2007 the permit was modified and issued in EOC's name. Per ADEM Rule 335-3-16-.12(2), an application for permit renewal shall be submitted at least six (6) months, but not more that eighteen (18) months, before the date of expiration of the permit. The renewal application was received on July 12, 2010. Additional information was requested on July 17, 2010 and October 25, 2010. The proposed MSOP would expire on January 6, 2016.

PROPOSED MODIFICATIONS

EOC has proposed the following modifications to the MSOP during this second Title V renewal:

- Add the requirements specified in Air Permit No.: 502-0007-X016 which was issued on February 4, 2010. EOC added two, 1,100 HP, White Superior, four stroke lean burn (4SLB) engines (designated ENG-01 and ENG-02 or WS engines) as part of their compression reliability project for the plant. During the permitting of these engines, applicability of the modified ENG-02 engine to the requirements of 40 CFR 60, Subpart JJJJ was not discussed. After further review, it was determined that although the unit did not meet the definition of construction or reconstruction, because this unit had been modified it would be subject to subpart JJJJ. No permit limits were included in permit X016; however, the ENG-02 engine would be subject to emission limits that would be included in the MSOP. Compliance testing requirements would be added to the permit for this engine to demonstrate compliance with subpart JJJJ. ENG-01 would not be subject to subpart JJJJ; however, since the facility would use a control device to maintain NO_X, CO, and VOC emissions below the PSD allowable emission rates these emission limits would also be included in the MSOP. Also, the facility would be required to test this unit annually to demonstrate that the emission limits are being met.

  Remove the applicable requirements of 40 CFR 63, Subpart ZZZZ from the permit for the existing 800 HP, two stroke lean burn (2SLB) Clark engines. The current permit has the two Clark engines incorrectly listed as 1,000 HP, four stroke rich burn

(4SRB) engines. However, in a letter dated November 28, 2007, EOC evaluated the engines during their November 27, 2007 performance test that was conducted on these units to demonstrate compliance with subpart ZZZZ. At this time, EOC determined that the engines were in fact 2SLB engines and requested that the Department remove the applicable requirements for this subpart from the permit. Since the Clark engines would be existing 2SLB engines, rather than existing 4SRB engines, they would be exempt from meeting the applicable requirements of this subpart as specified in 40 CFR §63.6590(b)(3)(i). The permit was never re-opened to remove these requirements.

- Add the requirements specified in Air Permit No.: 502-0007-X017 which was issued on February 4, 2010. EOC requested operating limitations for the two, existing 800 HP Clark engines (designated CM 11.01 and CM 11.02 or Clark engines) in order to maintain NO_X, CO, and VOC emissions below the PSD allowable emission rates during the compression reliability project. Permit X017 would restrict EOC from operating both Clark engines for more than 13,140 total cumulative hours per year.

- Remove reference to 40 CFR 63, Subpart DDDDD for the utility boilers found in the existing MSOP permit. This regulation was vacated by EPA on June 8, 2007. However, EPA has revisited this regulation. If and when this subpart is promulgated and it is adopted by the state, these units may be subject to the requirements of this subpart.

- Remove the tri-ethylene glycol (TEG) Plant No. 1 (designated GRV01) from the permit. This process is no longer in service. The TEG Plant No. 2 (designated GRV02) would have an increased inlet flow rate from 16.0 mmscf/day to its original design capacity of 25.0 mmscf/day. The vapors from the regenerator vent would be routed to either FL-02 or to the TEG re-boiler firebox. Flash vapors would be routed to the TEG re-boiler fuel system. The heat input for the TEG re-boilers at TEG Plant No. 2 (designated M102 & M1102) would increase from 1.14 MMBtu/hr to 4.092 MMBtu/hr. These modifications were part of the facility's compression reliability project.

- On January 3, 2007, area source requirements for 40 CFR 63, Subpart HH were promulgated by EPA. Because the BEC Plant would be designated as a major source of HAPs with respect to the regulation, the plant would not be affected by the area source requirements. The facility demonstrates exemption from the control requirements of this subpart for the glycol dehydration units by maintaining their benzene emissions below 1 ton per year.

- Change the Emergency Flare (FL02) to a process flare as proposed in the compression reliability project. The flare would now control vapors from the following processes:
  - DGA propane NGL treating plant regenerator vapors
  - Propane NGL loading vapors
  - TEG dehydration plant regenerator vapors

- Add the requirements of Air Permit No.: 502-0007-X018 for the 10,000 barrel storage tank (T101D) and the condensate loading/tank flare (FL05) with closed vent system. This permit was issued on September 28, 2010. The 10,000 barrel condensate storage tank would be subject to the applicable requirements of 40 CFR 60, Subpart K_b which would be added to this permit. The FL05 would be used to control the vapors from this storage tanks. Vapors from the group of equipment that would be associated with the condensate loading and unloading racks and that would be subject to 40 CFR 60, Subpart KKK would also be controlled by the FL05 flare.

- Add the applicable requirements of 40 CFR 60, Subpart K to the permit for the three (3) existing 5,000 barrel condensate storage tanks. It has been determined that these units do not meet the exemption specified in §60.110(b) of Subpart K because the condensate stored in these tanks would not be stored prior to custody transfer.

- Add the requirements of Air Permit No.: 502-0007-X019 issued on September 28, 2010 for the condensate loading racks (LOAD-01A & LOAD-01B) and unloading rack (UNLOAD-01).

PROCESS DESCRIPTION

The BEC Plant produces the following products/by-products from sour natural gas/condensate treating/processing: sweet (residue) natural gas, sweet stability condensate, sweet natural gas liquids (NGL) consisting of propane, butane, and pentane plus, and elemental sulfur. The BEC Plant consists of the following processes:

- High pressure (HP) and low (LP) pressure inlet three (3) phase separation;

- A propane refrigeration plant (the RECO plant) for hydrocarbon dew-point reduction resulting in a small volume of NGL recovery from the HP sour natural gas inlet stream;

- A condensate stabilization plant that provides:
  - Condensate/NGL sweetening from 200,000 ppm to 50 ppm H_2S concentration; and,
  - Vapor pressure reduction of HP/LP condensate (from inlet separation); and, vapor pressure reduction of NGL from the RECO plant.

- A caustic wash system for sour condensate/NGL sweetening;

- A vapor recovery unit (VRU) which would control vapors from the follow processes;
  - Condensate stabilization plant over-head vapor collection; and
  - Amine treating plant flash vapor collection.

- An amine treating plant for H_2S/CO_2 removal from the following gas streams:
  - The HP sour natural gas stream;
  - The LP sour natural gas stream; and,
  - Sour gas vapors from the condensate stabilization plant.

- A sulfur recovery unit (SRU) for treatment of acid gas from amine regeneration; a thermal oxidizer for combusting tail gas from the SRU

- Cryogenic plant inlet compression;

- A dehydration plant (with tri-ethylene glycol —TEG system; and, mole sieve system);

- A cryogenic/fractionation plant; with residue gas compression;

- A di-glycol amine (DGA) treating plant (for NGL carbonyl sulfide - COS reduction; from 100 ppm to 0.0 ppm);

- NGL storage/loading;

- Condensate blending and storage;

- Condensate loading (LOAD-01A & LOAD-01B) and unloading racks (UNLOAD-01).

- Process Flares (FL-02, FL-03 and FL-05)

- Emergency Flare (FL-04)

➢ BEC plant miscellaneous process support systems
  - A process steam generation system;
  - A salt-water/produced water well disposal (SWD) system;
  - Flare systems for waste vapor control; and,
  - A vapor recovery unit/system (VRU) for waste vapor control

EMISSIONS

Facility wide potential emissions for the BEC Plant are given below. The emissions were obtained from the facility's renewal application.

Potential Facility Wide Emissions from BEC Plant (TPY)						
	$PM_{2.5}/PM_{10}$	**SO_2**	**NO_X**	**CO**	**VOC**	**Total HAPs**
POTENTIAL EMISSIONS	14.36	20,710.02	477.07	261.12	573.44	366.31

BIG ESCAMBIA CREEK OIL& GAS PRODUCTION TREATING & PROCESSING FACILITY
FACILITY NO.: 502-0007

FACILITY PERMITTING HISTORY

Permit No.	Permit Description	Construction Permit Issued (X)	TAO Issued (Y)	Operating Permit Issued (Z)
Mallard Exploration, Inc				**1973**
001	Process Heat Boiler	September 4,1973	May 6, 1974	November 18, 1974
002	Sulfur Recovery Plant No. 1 w/Thermal Oxidizer	September 4,1973	May 6, 1974 November 4, 1974 January 15, 1975	February 18, 1975
003	Smokeless Flare No. 1 Removed from service during the 1st Title V Renewal	- -	- -	January 30, 1975 July 2005
004	113,452 Gallon Propane Storage Tank V-517-A	February 12, 1975	-	March 13, 1975
005	113,452 Gallon Propane Storage Tank V-517-B	February 12, 1975	-	March 13, 1975
006	85,119 Gallon Butane Storage Tank V-518-A	February 12, 1975	-	March 13, 1975
007	85,119 Gallon Butane Storage Tank V-518-B	February 12, 1975	-	March 13, 1975
008	Two Process Heat Boilers (80 MMBtu/hr Each)	May 28, 1976	-	August 29, 1977
009	Sulfur Recovery Plant No. 2 w/Thermal Oxidizer Permit re-issued to revise continuous total sulfur rate monitors Permit re-issued as a result of the September 19, 2002 consent order; modified thermal oxidizer to be able to meet a 95% destruction efficiency	May 28, 1976 - -	February 27, 1978 - -	April 11, 1978 September 7, 1988 July 7, 2003
010	Smokeless Flare No. 2	May 28, 1976	August 29, 1977	August 29, 1977
011	420,000 Gallon Storage Tank (T-1101) Facility requested to remove this unit in the permit application	May 28, 1976 -	- -	August 29, 1977 December 11, 1976
012	Smokeless Flare No. 3 (Solar Compressor Flare) Facility requested to remove this unit due to the dismantling of Compressor Station No. 1	July 10,1978 -	January 9, 1979 -	April 10, 1979 April 10,1990
Exxon Company (A Division of Exxon Corporation) acquired facility from Mallard Exploration, Inc				**June 1, 1979**
001-012	All existing permits issued to the new owners			June 18, 1979
013	800 HP NG Fired Waukesha L7042G Compressor Engine w/catalytic converters Facility requested to remove this unit due to the dismantling of Compressor Station No. 1	December 29, 1982 -	October 15, 1983 -	December 21, 1983 April 10,1990
014	Intermediate Pressure Separation and Compression Units and Inlet Cooling Unit (NSPS KKK)	June 30, 1987	October 31, 1987	-

FACILITY PERMITTING HISTORY

Permit No.	Permit Description	Construction Permit Issued (X)	TAO Issued (Y)	Operating Permit Issued (Z)
015	Produced Water Handling Facility: 5,000 Barrel Storage Tank 750 Barrel Separator/Truck Unloading Tank 35 Barrel Oil Collection Tank Vapor Recovery System Water Flare No. 4	-	-	March 21, 1994
Initial Title V Permit Issued				January 8, 2001 w/expiration of January 7, 2006
Vintage Petroleum, Inc. acquired facility from Exxon Company				**January 1, 2005**
1st Title V Renewal Issued				July 6, 2006 w/expiration of January 7, 2006
1st Title V Renewal Modified to include the requirement to oxidize 95% or more of TRS compounds leaving the sulfur recovery unit.				September 6, 2006
Escambia Operating Company, LLC (Subsidiary of Eagle Rock Energy Company) acquired facility from Vintage Petroleum				**June 1, 2006**
1st Title V Renewal Modified to add BART requirements for the SRU/Thermal Oxidizer; issued to new owners				December 10, 2007
016	Two 1,100 HP White Superior (8GTLB), 4SLB Inlet Gas/Residue Gas Compressor Engine (ENG-01 & ENG-02)			February 4, 2010
017	Placed operating limits on the two 800 HP, 2SLB Clark engines originally permitted under X013			February 4, 2010
018	10,000 Barrel Fixed Roof Condensate Storage Tank (T101D) Condensate Loading/Tank Flare with Closed Vent System (FL-05)			September 28, 2010
019	Blended Condensate Truck Loading Racks with Closed Vent System (LOAD-01A & LOAD-01B) Imported Condensate Truck Unloading Rack with Closed Vent System (UNLOAD-01)			September 28, 2010

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FACILITY-WIDE EMISSIONS

Applicable facility-wide regulations for the BEC Plant are found in the following table:

Emission Point	Description	Pollutant	Emission Limit	Regulations
Sources:				
Petroleum Production Facility		H_2S	Burn gas with > 0.10 grains of H_2S/scf of gas	Rule 335-3-5-.03(1)
			20 ppbv offsite	Rule 335-3-5-.03(2)
		SO_2	Depends on available sulfur and % H_2S in acid gas	Rule 335-3-5-.03(3) Rule 335-3-5-.03(3)(a)
		Total Sulfur Compound	Depends on available sulfur	Rule 335-3-5-.03(4)(a)
Onshore Natural Gas Processing Plants				
All affected facilities: Compressors in VOC or wet gas service Group of all equipment Dehydration Units Sweetening Unit LNG Unit Process Units: Inlet Gathering and Separation Unit Condensate Stabilization Unit Gas Sweetening Units De-Methanizing Unit De-Propanizing Unit De-Butanizing Unit Sulfur Recovery Unit Produced and Process Water System Closed vent System with Flare Condensate Loading and Unloading Racks		VOC	LDAR work practices	40 CFR 60 Subpart KKK
Oil and Natural Gas Production Facilities				
All affected sources: Compressors in VHAP service located at a natural gas processing plant Group of all ancillary equipment located at a natural gas processing plant: Each valve Each pump Each pressure relief device Each sampling connection system Each open-ended valve or line Each flange or other connector Each glycol dehydration unit Each storage vessels with the potential for flash emissions		HAPs	LDAR work practices	40 CFR 63, Subpart HH (Oil and Gas MACT)

FACILITY-WIDE EMISSIONS

The BEC Plant's applicability to the state and federal regulations would be discussed in the following sections.

STATE REGULATIONS

Applicability:

- ADEM Admin. Code R. 335-3-5-.03(1), "*Petroleum Production*" applies to the control of sulfur compound emissions from each petroleum production facility that handles gas or refinery gas that contains more than 0.10 grains of hydrogen sulfide (H_2S) per standard cubic foot (scf) of gas. The BEC Plant would handle sour gas that contains 0.10 grain of H_2S/scf of gas or more; therefore, the facility would be subject to the applicable requirements of this regulation. The sulfur recovery unit/thermal oxidizer and flares would be used to comply with this regulation.

Emission Standards:

- In order to meet the applicability requirements of ADEM Admin. Code R. 335-3-5-.03(2), all process gas containing greater than 0.10 grains of H_2S/scf shall be burned to the extent that the ground level concentrations of hydrogen sulfide are less than twenty (20) parts per billion beyond plant property limits, average over a thirty (30) minute period.

  ADEM Admin. Code R. 335-3-5-.03(3), would define the sulfur dioxide (SO_2) emission allowable for Category II counties. Escambia County, where the BEC Plant is located, would be classified as a Category II county. The allowable SO_2 emissions for Category II counties would be based on the amount of available sulfur processed and the H_2S content in the acid gas stream as specified in this regulation.

  ADEM Admin. Code R. 335-3-5-.03(4) would be applicable to the BEC Plant because it would process natural gas in Escambia County that has a capacity greater than 50 million standard cubic feet of sour gas per day (50 MMscf/day). This regulation specifies the permitted total sulfur compound allowable based on the available sulfur coming into the plant.

- Each process gas stream that has to be vented to the atmosphere should be first captured and sent to the thermal oxidizer or designated flare to be burned. Except for a period not to exceed 15 continuous minutes while depressurizing and/or empting equipment and when reduced pressure will not allow flow of gas to a control device, venting to atmosphere would not be allowed.

Compliance and Performance Test Methods and Procedures:

- Compliance with the requirement to burn gas containing 0.10 grains of H_2S/scf of gas would be demonstrated by sweetening the sour gas and sending the acid gas to the

FACILITY-WIDE EMISSIONS

sulfur recovery unit, by routing the tail gas from the sulfur recovery unit to the thermal oxidizer, and routing process vapors to their respective flares for combustion. Compliance would also met by sampling and testing all sour gas streams that can be vented to atmosphere for its H_2S content (mol %).

- Compliance with the requirement to maintain the ground level concentrations of hydrogen sulfide at less than twenty (20) parts per billion beyond plant property limits averaged over a thirty (30) minute period shall be met by maintaining the sulfur recovery efficiency and SO_2 emission rate below its allowable, by maintaining the assist gas to acid gas volume ratio at greater than or equal to 1 for the FL02 flare, and by maintaining the thermal oxidizer firebox temperature as required by the permit.

Emission Monitoring:

- Monitoring to demonstrate compliance with the requirement to burn gas with more than 0.10 grains of H_2S per scf of gas would be met by monitoring the flares, SRU, and thermal oxidizer as required by the existing permit. This renewal will not result any changes to monitoring for these units.

- Compliance with the requirement to maintain the permitted total sulfur compound emissions below its allowable shall be met by continuously monitoring the total sulfur compounds, measured as sulfur dioxide, emitted by the facility and the total available sulfur entering the plant. Other equivalent methods of monitoring may be approved by the Department.

Recordkeeping and Reporting Requirements:

- The facility's record keeping and reporting requirements would be met by performing monthly calculations for the engines, boilers, thermal oxidizer, sulfur recovery unit, and flares.

Applicability:

- ADEM Admin. Code R. 335-3-14-.04 "*Prevention of Significant Deterioration (PSD) Permitting",* would be subject to the BEC Plant. The BEC Plant was issued its first construction permits on September 4, 1973 and operating permits on November 18, 1974. The permit issuance dates occurred prior to PSD regulations being promulgated by EPA on June 19, 1978 and being adopted by the state on December 10, 1981; therefore, the facility would be considered a grandfathered source with respect to PSD regulations. In order for the facility to keep its status as a grandfathered source with respect to PSD, it would be required not to exceed the significant emission rates found in 335-3-14-.04(2)(w) for each project thereafter.

Applicability:

- ADEM Admin. Code R. 335-3-16-.03, "*Major Source Operating Permits"* would be subject to the BEC Plant. The BEC Plant has been deemed a major source of criteria pollutants (have the potential to exceed 100 tons per year (TPY) or more) and a major

FACILITY-WIDE EMISSIONS

source of hazardous air pollutants (HAPs) emissions (have the potential to exceed 10 TPY or more for a single HAPs or 25 TPY or more for a combination of HAPs). Therefore, the BEC Plant would be subject to the requirements of this regulation.

FEDERAL REGULATIONS

New Source Performance Standards (NSPS)

Applicability:

- 40 CFR 60 *Subpart A, "General Provisions"* would be subject to the BEC Plant provided that the facility would be subject to one of the applicable subparts found under part 60.

Applicability:

- 40 CFR 60 Subpart LLL, *"Standards of Performance for Onshore Natural Gas Processing: SO_2 emissions"*, would not be applicable to each sweetening unit and each sweetening unit followed by a sulfur recovery unit (SRU) (40 CFR §60.640(a)). The BEC Plant would be equipped with an amine sweetening unit that removes carbon dioxide (CO_2) and H_2S from the sour gas and would be followed by a sulfur recovery unit; however, these units were constructed prior to the January 20, 1984 compliance date for this regulation.

On January 11, 1985, Exxon Company, the facility owner at the time, proposed injecting nitrogen (N_2) into the wells being produced at the BEC Plant. In order to do this they proposed that a contaminated gas treating unit (CGTU) be installed at the BEC Plant to process the produced gas contaminated with N_2. The facility sought the guidance of EPA to determine what effects this project would have on its applicability to subpart LLL. EPA determined that as long as the proposed changes did not cause an increase in sulfur dioxide emissions from the sweetening unit or the SRU to the atmosphere, adding the CGTU or making any of the proposed changes would not qualify as a modification. Reconstruction would occur only if the cost of the proposed changes would be greater than 50% of constructing a new sweetening unit or SRU.

In a letter dated June 10, 2003, the Department expressed concerns about the facility triggering subpart LLL as a result of making major repairs to replace portions of equipment during maintenance project. The facility proposed making significant repairs to the north and south solvent regeneration towns in train No. 2 of the sweetening unit along with replacing the lower portion of the north solvent regeneration tower, two air/solvent exchangers, and a reactor in train No. 2 of the SRU. The Department determined that reconstruction had not occurred; however, it was not sure that a modification had not occurred. Although, the facility was able to demonstrate in a letter dated November 25, 2003, that a modification had not occurred as a result of the maintenance project.

These projects were determined not to result in a modification as specified in §60.14

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or reconstruction as specified in §60.15; therefore, the BEC Plant would not be subject to the applicable requirements of this subpart LLL.

Applicability:

40 CFR 60 Subpart KKK, *"Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOC) From Onshore Natural Gas Processing Plants"*, would be applicable to the BEC Plant since the plant meets the definition of a natural gas processing plant. A natural gas processing plant constructed after the January 20, 1984 compliance date for this subpart would be subject to this regulation. This regulation would be applicable to affected facilities that include compressors in VOC service or in wet gas service (40 CFR §60.630 (a)(2)) and the group of all equipment within a process unit (40 CFR §60.630 (a)(3)). Equipment would be defined in this subpart as pumps, pressure relief devices, open-ended valve or line, valves, compressors (except reciprocating compressors in wet gas service (40 CFR §60.633 (f)), and flanges or other connectors that are in VOC service or wet gas service. The facility's dehydration units, sweetening unit, field gas gathering system, and liquefied natural gas unit would also be covered by this subpart since they would be located at this facility (40 CFR §60.630 (e)).

The BEC Plant was constructed prior to the January 20, 1984 compliance date; however, several projects occurred after this compliance date that affected the facility's applicability to this regulation. The projects were as follows: the 1987 installation of the solar compressors, the inlet cooling system within the inlet gathering and separating system, and the vapor recovery system within the sweetening unit; the 1988 relocation of the solar compressors to the outlet of the high pressure sweetening train and all of the related inlet and sweetening unit changes that were needed to allow the relocation and direct feed into the low pressure sweetening; the 1992 modifications to the inlet blow down system; the 1994 installation of a salt water handling system; the 1996 modifications to inlet header manifold; and the 1998 modifications to allow the solar compressors to be placed in series. These projects resulted in the facility being subject to the requirements of this subpart and a LDAR program for these projects was implemented in 2000.

Emission Standards:

- To demonstrate compliance with the applicable requirements of 40 CFR 60 Subpart KKK, the emission standards found in 40 CFR §60.632 shall be met, except as provided in 40 CFR §60.633. The emissions standards for Subpart KKK refer to 40 CFR 60 Subpart VV, "*Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry*".

Compliance and Performance Test Methods and Procedures:

- Compliance with the emissions standards of this subpart shall be demonstrated through the review of records and reports, review of performance test results, and inspection using the methods and procedures specified in 40 CFR §60.485, except as specified in 40 CFR §60.633(f) (40 CFR §60.632(d) of Subpart KKK and 40 CFR

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§60.482-1(b) of Subpart VV).

Emission Monitoring:

- Compliance with the monitoring requirements of this subpart shall be demonstrated by meeting the inspection and monitoring requirements specified in 40 CFR §60.482-1 through §60.482-10 of Subpart VV. Sampling connection systems are exempt from the requirements found in 40 CFR §60.482-5 (40 CFR §60.633(c)). Alternative methods of monitoring valves may be elected as specified in either 40 CFR §60.483-1 or §60.483-2 of Subpart VV (40 CFR §60.632(a) & (b) of Subpart KKK).

Recordkeeping and Reporting Requirements:

- Compliance with the recordkeeping requirements of this subpart shall be met by complying with 40 CFR §60.486 of Subpart VV and as specified in 40 CFR §60.633 and §60.635 of Subpart KKK (40 CFR §60.632 (e) of Subpart KKK).

- Compliance with the reporting requirements of this subpart shall be met by complying with 40 CFR §60.487 of Subpart VV and as specified in 40 CFR §60.633 and §60.636 of Subpart KKK (40 CFR §60.632 (e) of Subpart KKK).

  - A Leak Detection and Repair (LDAR) summary report shall be submitted to the Department. The report shall be submitted semi-annually on calendar basis within 30 days of the end of the reporting period.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

Applicability:

- 40 CFR 63, Subpart A, *"General Provisions"*, would be subject to the BEC Plant because the plant would be subject to 40 CFR 63, Subpart HH. Table 2 of Subpart HH would specify which provisions of subpart A apply and those that do not apply (40 CFR §60.764(a)).

Applicability:

- 40 CFR 63 Subpart HH, *"National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities",* this subpart would apply to facilities that are a major source or area source of HAPs (40 CFR §63.760(a)(1)) and either process, upgrade, or store hydrocarbon liquids prior to the point of custody transfer (40 CFR §63.760(a)(2)) or process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user (40 CFR §63.760(a)(3)). Affected sources for a major source would be consist of each glycol dehydration unit, each storage vessel with the potential for flash emissions, the group of all ancillary equipment, except compressors, intended to operating in volatile hazardous air pollutant (VHAP) service located at a natural gas process plant, and compressor intended to operate in VHAP service located at a natural gas processing plant (40 CFR §63.760(b)(1)). A major source of HAPs under this subpart requires a potential to emit 10 TPY or more of one HAP or 25 TPY or more of a combination of HAPs (40 CFR §63.2 and §63.761). The BEC Plant would be a major source of HAP emissions.

- The 5,000 barrel and 10,000 barrel condensate storage tanks would not be operated as storage vessels with the potential for flash emissions as defined in 40 CFR §63.761. Fugitive emissions from the ancillary equipment and compressors would meet the requirements specified in 40 CFR 60, Subpart KKK; therefore, these units would not be subject to the equipment leak standards found under this subpart (40 CFR §63.769 (b)).

- A glycol dehydration unit process vent located at a major source of HAPs would be subject to the applicable requirements of this subpart if it has an actual annual average natural gas flow rate equal to or greater than 85 thousand standard cubic meter per day and actual average benzene glycol dehydration unit process vent emissions greater than or equal to 0.90 megagrams per year (1.0 TPY) (40 CFR §63.665(a)). The glycol dehydration process vent would consist of both the glycol dehydration unit reboiler vent and the vent from the gas-condensate-glycol (GCG) separator (flash tank). The BEC Plant would be subject to the applicable requirements for this subpart.

  The BEC Plant would have HAP emissions greater than 10 TPY or more for a single HAP or greater than 25 TPY or more for a combination of HAPs; therefore, it would be a major source of HAPs. Initially, the uncontrolled emissions from the glycol dehydration vent were greater than 1 TPY; however, prior to the June 17, 2002 compliance date for this subpart the facility was able to demonstrate exemption from the emission standards found in §63.764 (c)(1). Controls were placed on both the glycol dehydration unit reboiler vent and the vent from the GCG separator in order to maintain the actual average benzene emission from this unit below 0.90 megagrams per year (40 CFR §63.764(e)(1)(ii)). Therefore, the BEC Plant was classified as a minor source of HAPs with respect to this subpart. The facility's applicability determination for subpart HH, can be found in a report dated June 10, 2002.

  On January 3, 2007, the area source requirements under 40 CFR 63 Subpart HH were promulgated by EPA. Because the BEC Plant was not considered a major source of HAPs with respect to this subpart, it became an area source of HAPs. In order to be an affected source at an area source of HAPs, the facility had to be equipped with a tri-ethylene glycol (TEG) dehydration unit (40 CFR §63.760(b)(2)). The BEC Plant was equipped with a TEG unit; therefore, it was subject to the area source requirements of this subpart. However, the facility was able to avoid having to meet the applicable control and monitoring requirements for the TEG unit by complying with the exemptions specified in either §63.764(e)(1)(ii) and by maintaining the records of determination as required by 40 CFR §63.774(d)(1) (40 CFR §63.764 (e)(1)). No further requirements were required of the facility for the TEG dehydration unit, because the facility was already meeting the exemption for the subpart by maintaining the benzene emissions at less than 1 TPY. The same exemptions for the glycol dehydration process vent found in 40 CFR §63.764 (e)(1)

FACILITY-WIDE EMISSIONS

applies to affected sources at both a major source of HAPs and an area source of HAPs.

Emission Standards:

- To demonstrate that the BEC Plant would not be a major source of HAPs under this subpart, the facility must maintain the actual average benzene emissions from the glycol dehydration unit process vent below 1 TPY by meeting the following requirements:
  - Installing and operating one of the following controls on the GCG separator (flash tank) vent, to reduce HAP emissions by 95% or more or reduce benzene emissions to a level less than 0.90 megagrams per year as specified in §63.775(b)(1):
    - Capture the vapors leaving the process vent with a closed vent system and send them to a control device (40 CFR §63.765 (b)(1)(i))
    - Capture the vapors leaving the process vent with a closed vent system and send them to a control device to reduce the outlet benzene emissions to a level less than 0.90 megagrams per year (1,982 lbs/yr) (40 CFR §63.765 (b)(1)(ii))
    - Control the vapors leaving the process line with a closed vent system and send them to a process line (40 CFR §63.765 (c)(1))
    - Undertake a process and/or control device modification in accordance to §63.771 (e) to demonstrate that the total HAP emissions to the atmosphere from the glycol dehydration unit process vent are reduced by 95% (40 CFR §63.765 (c))
  - Routing vapors from the glycol dehydration reboiler vent (GRV02) through a closed vent system that meets the requirements specified in §63.771 (c) to one of the following control devices:
    - A condenser; the uncondensed vapors would be vented to atmosphere (40 CFR §63.771(d)(1)(ii)) (Currently the facility is using a water-cooled condenser to control HAP emissions; however, they have proposed directing the vapors to the FL02 flare or to the TEG re-boiler for VOC control)
    - A flare subject to 40 CFR §63.11(b) (40 CFR §63.771(d)(1)(iii))
- To be exempt from having to meet the general standards for a TEG dehydration unit located at an area source of HAPs (40 CFR §63.764 (d)), the facility has to either maintain the actual annual average flowarate of natural gas to the glycol dehydration unit at less than 85 thousand standard cubic meters per day or maintain the actual average emissions of benzene from the glycol dehydration unit process vent to the atmosphere at less than 0.90 megagram per year (40 CFR §63.764 (e)(1)(i) or (e)(1)(ii)). The facility would demonstrate compliance with this exemption by maintaining the actual average emissions of benzene from the glycol dehydration unit

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process vent to the atmosphere at less than 0.90 megagram per year.

Compliance and Performance Test Methods and Procedures:

- Neither a performance test nor a design analyses would not be required for flare designed to meet §63.11(b) (§63.772(e)(1)(i)); however, a compliance determination shall be conducted using Method 22 of 40 CFR part 60, Appendix A, to determine visible emissions from the flare (§63.772(e)(2)(i)).

- To demonstrate that the condenser used to control emissions from the glycol dehydration unit process vent meets the control requirements of §63.771(d)(1), the facility may elect to perform one of the following:

  - Conduct a performance test using the methods and procedures specified in §63.772(e)(3)

  - Conduct a design analysis meeting the requirements specified in §63.772(e)(4)(i)(D)

  - Use the alternative procedures specified in §63.772(e)(5)

- To demonstrate exemption from the general standards for an affected area source, the facility must meet one of the following:

  - Follow the procedures specified in 40 CFR §63.772 (b)(1) to demonstrate that the actual annual average flowarate of natural gas to the glycol dehydration unit is less than 85 thousand standard cubic meters per day the facility (40 CFR §63.764 (e)(1)(i))

  - Follow the procedures specified in 40 CFR §63.772 (b)(2) to demonstrate that the actual average emissions of benzene from the glycol dehydration unit process vent to the atmosphere has to be less than 0.90 megagram per year (40 CFR §63.764 (e)(1)(ii))

Emission Monitoring:

- Monitoring for a closed vent system shall be met as specified in §63.773(c)

- Monitoring for a control device shall be met as specified in §63.773(d)

Recordkeeping and Reporting Requirements:

- A record of each event when the benzene emissions from glycol dehydrator reboiler vent or the GCG separator are not being controlled by one the methods specified in the emission standards section.

- Maintain determination records to demonstrate exemption from the general standards

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for an affected area source as specified in 40 CFR §63.774(d)(1) (40 CFR §63.764 (e)(1)).

- If a flare is used to comply with 40 CFR §63.771 (d), the following records shall be maintained (40 CFR §63.774(e)(1) through (3)):
    - o Flare design
    - o All visible emission readings,
    - o Heat content determinations, flowrate measurements, and exit velocity determinations made during the compliance determination required by §63.772(e)(2);
    - o All hourly records and other recorded periods when the pilot flame is absent
- No reporting requirements would be required for a glycol dehydration unit exempt from the control requirements for glycol dehydration unit process vents specified in §63.765 (40 CFR §63.775 (b)(7)).
- A Periodic Report meeting the requirements specified in §63.775 (e)(3) shall only be required for an area source if it is located in a UA plus offset and UC boundary. Periodic reports for subpart HH would not be required for the BEC Plant; however, the Department requires that the facility submit a report of any deviations that occur during the reporting period. The report shall be submitted semi-annual on a calendar basis within thirty days of the end of the reporting period.

Emissions

	Expected Emissions from Affected Sources (TPY)					
Source ID	**$PM_{2.5}/PM_{10}$**	**SO_2**	**NO_X**	**CO**	**VOC**	**Total HAPs**
M101	0.13	0.011	1.76	1.48	15.54	1.32
M102	0.134	0.011	1.76	1.48	15.54	1.32
GRV02	-	-	-	-	-	-
TOTAL EXPECTED EMISSIONS	**0.264**	**0.022**	**3.52**	**2.96**	**31.08**	**2.64**

UTILITY BOILERS EMISSIONS

Emission Point	Description	Pollutant	Emission Limit	Regulations
(B0301A)	**97 MMBtu/Hour, Natural Gas-Fired, Utility Boiler (No. 1 Steam Plant South Boiler)**	PM	0.21 Lbs/ MMBTU of heat input	Rule 335-3-4-.03(2)
		SO_2	4 Lbs/MMBTU of heat input	Rule 335-3-5-.01(1)(b)
		NO_X	NONE	
		VOC	NONE	
		CO	NONE	
		Opacity	No more than one 6 min avg. > 20% AND	Rule 335-3-4-.01(1)(a)
			No 6 min avg. > 40%	Rule 335-3-4-.01(1)(b)
(B0301B)	**97 MMBtu/Hour, Natural Gas-Fired, Utility Boiler (No. 1 Steam Plant North Boiler)**	PM	0.21 Lbs/ MMBTU of heat input	Rule 335-3-4-.03(2)
		SO_2	4 Lbs/MMBTU of heat input	Rule 335-3-5-.01(1)(b)
		NO_X	NONE	
		VOC	NONE	
		CO	NONE	
		Opacity	No more than one 6 min avg. > 20% AND	Rule 335-3-4-.01(1)(a)
			No 6 min avg. > 40%	Rule 335-3-4-.01(1)(b)
(B01301A)	**97 MMBtu/Hour, Natural Gas-Fired, Utility Boiler (No. 2 Steam Plant South Boiler)**	PM	0.21 Lbs/ MMBTU of heat input	Rule 335-3-4-.03(2)
		SO_2	4 Lbs/MMBTU of heat input	Rule 335-3-5-.01(1)(b)
		NO_X	NONE	
		VOC	NONE	
		CO	NONE	
		Opacity	No more than one 6 min avg. > 20% AND	Rule 335-3-4-.01(1)(a)
			No 6 min avg. > 40%	Rule 335-3-4-.01(1)(b)
(B01301B)	**97 MMBtu/Hour, Natural Gas-Fired, Utility Boiler (No. 2 Steam Plant North Boiler)**	PM	0.21 Lbs/ MMBTU of heat input	Rule 335-3-4-.03(2)
		SO_2	4 Lbs/MMBTU of heat input	Rule 335-3-5-.01(1)(b)
		NO_X	NONE	
		VOC	NONE	
		CO	NONE	
		Opacity	No more than one 6 min avg. > 20% AND	Rule 335-3-4-.01(1)(a)
			No 6 min avg. > 40%	Rule 335-3-4-.01(1)(b)

The following sections discuss the utility boilers' applicability to state and federal regulations:

UTILITY BOILERS EMISSIONS

STATE REGULATIONS

Applicability:

- ADEM Admin. Code R. 335-3-4-.01, "*Visible Emissions*" for Control of Particulate Emissions, would be applicable to stationary sources. The boilers would each be subject to the requirements of this regulation.

Emission Standards:

- The boilers would be required to meet the 20% and 40% opacity requirement as specified in ADEM Admin. Code R. 335-3-4-.01(1) (a) and (b).

Compliance and Performance Test Methods and Procedures:

- Provided that visible emissions in excess of the opacity standards are observed from the boilers, a visible emissions observation (VEO) shall be conducted using the methods specified in EPA Method 9 or Method 22.

Emission Monitoring:

- These units would burn natural gas as their fuel source. The expected particulate emissions from burning natural gas should be negligible; therefore, no daily opacity monitoring would be required for these units. However, if visible emissions are observed from these units in excess of the opacity standards, a VEO would be required.

Recordkeeping and Reporting Requirements:

- A record of each visible emissions observation conducted when necessary.

Applicability:

- ADEM Admin. Code R. 335-3-4-.03(2), "*Fuel Burning Equipment*" for Control of Particulate Emissions would be applicable to stationary sources. This regulation would apply to fuel burning equipment located in a Class II County. Escambia County would be considered a Class II County under this regulation; therefore, the boilers would be subject to the applicable requirements of this regulation.

Emission Standards:

- Particulate matter (PM) emissions from the utility boilers shall not exceed the allowable as determined by the following equation:

$$E= [3.109] * [H^{-0.589}]$$

UTILITY BOILERS EMISSIONS

where, E= Emissions (lb/MMBtu) and H= Heat Input (MMBtu/hr)

Compliance and Performance Test Methods and Procedures:

- If testing is required by the Department, particulate matter (PM) emission shall be determined in accordance with Method 5 of 40 CFR 60, Appendix A.

Emission Monitoring:

- Based on the permit application the potential emissions from the boilers would not be expected to exceed the allowable PM emissions; therefore, no PM monitoring would be required.

Recordkeeping and Reporting Requirements:

- No recordkeeping or reporting would be required for the boilers under this regulation.

Applicability:

- ADEM Admin. Code R. 335-3-5-.01(1)(b), "*Fuel Combustion*", limits SO_2 emissions from fuel burning equipment in Category II counties. The utility boilers would be subject to the requirements of this regulation.

Emission Standards:

- SO_2 emissions from fuel burning equipment in Category II counties would be limited to 4.0 pounds per million BTU of heat input (lb/MMBtu of heat input). Each utility boiler would be subject to this limit.

Compliance and Performance Test Methods and Procedures:

- To demonstrate compliance with the SO_2 emission limits, the facility would be required to test the fuel gas of the boilers for its heat content and hydrogen sulfide concentration no less than once each twelve months. The Btu content would be analyzed using ASTM Analysis Method D1826-77 or equivalent method. The H_2S concentration would be analyzed using the Tutwiler procedures found in 40 CFR 60.648, the chromatographic analysis procedures found in ASTM E-260, the stain tube procedures found in GPA 2377-8, or those provided by the stain tube manufacture.

Emission Monitoring:

- SO_2 monitoring for the boilers and heaters under this regulation shall be in the form of maintaining records of the SO_2 emissions.

UTILITY BOILERS EMISSIONS

Recordkeeping and Reporting Requirements:

- A monthly record of the deviations, maintenance, operating hours (Hours/Month), fuel heat content (Btu/scf), H_2S content (ppmv), fuel gas consumption (in units of Mscf/day and Mscf/Month), and SO_2 emissions (Lbs SO_2/MMBtu) would be maintained to demonstrate compliance with the emission standards for the boilers and heaters.

  The allowable SO_2 emissions shall be determined using the following equation:

  $$\text{Lbs } SO_2/\text{MMBTU} = \frac{[\,[\text{Fuel } H_2S \text{ (ppmv)}\,] \times [0.1684]}{[\text{Fuel Heat Content (BTU/Scf)}]}$$

  where 0.1684 would be the conversion factor determined as follows: [1 lb-mol/380 scf] X [34 lbH_2S/lb-mol] X [64 lb SO_2/34 lb H_2S]

Applicability:

- ADEM Admin. Code R. 335-3-14-.04 *"Prevention of Significant Deterioration (PSD) Permitting".* As stated previously in the facility-wide emission section, the BEC Plant would be a grandfathered source with respect to PSD regulations. As long as each new project at an existing major stationary source does not exceed the significant emission rates found in 335-3-14-.04(2)(w), the facility's status as a grandfathered source under PSD regulations would not change. Based on the facility files there have not been any new projects for boilers which would have affected the facility's status as a grandfathered source.

Applicability:

- ADEM Admin. Code R. 335-3-16-.03, "*Major Source Operating Permits".* The BEC Plant has been deemed a major source of criteria pollutants and HAP emissions. The utility boilers located at this facility would be subject to the requirements of this regulation.

FEDERAL REGULATIONS

New Source Performance Standards (NSPS)

Applicability:

- 40 CFR 60 *Subpart A, "General Provisions"* would be subject to the boilers provided that these units would be subject to one of the applicable subparts found under part 60.

Applicability:

- 40 CFR 60 Subpart D, "*Standards of Performance for Fossil-Fuel Fired Steam Generators for which construction is commenced after August 17, 1971",* would not be applicable to the any of the boilers located at the BEC Plant because each units' heat input rate would not be greater than 250 MMBtu/hr (40 CFR §60.40(a)(1)).

UTILITY BOILERS EMISSIONS

Applicability:

- 40 CFR 60 Subpart D, "*Standards of Performance for Fossil-Fuel-Fired Steam Generators for which construction commenced after August 17, 1971"* would apply to each fossil-fuel-fired steam generating unit of more than 250 MMBtu/hr heat input and each fossil-fuel and wood-residue-fuel fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 250 MMBtu/hr *(*40 CFR §60.40(a)(1) and (2)). Each of the boilers would burn natural gas as their fuel source; however, neither of the utility boilers would have a heat input of greater than 250 MMBtu/hr. These boilers also would not be capable of firing fossil fuel at heat input rate of more than 250 MMBtu/hr without exceeding their SO_2 emission limits under ADEM Admin. Code R. 335-3-5-.01(1)(b). Therefore, these boilers would not be subject to the requirements of this subpart.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

Applicability:

- 40 CFR 63, Subpart A, *"General Provisions"*, would be subject to the boilers provided that these units would be subject to one of the applicable subparts found under part 63.

Applicability:

- 40 CFR 63 Subpart DDDDD, "*National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*". The utility boilers at the BEC Plant would not be subject to the requirements of this subpart at this time. The current permit contains applicability to this subpart; however, any reference to this subpart would be removed from the permit because EPA vacated this regulation on June 8, 2007. Provided that this subpart is promulgated again in the future, the BEC Plant may be subject to the requirements of this subpart.

Applicability:

- 40 CFR 64, "*Compliance Assurance Monitoring (CAM)*" would not be subject to the utility boilers because they would not meet all of the requirements of this regulation as follows: have an emission limit or standard, use a control device to achieve compliance with the emissions limit or standard, and have pre-controlled emissions from a regulated air pollutants that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source (40 CFR §64.2(a)). Each boiler would have an emission limit in place for SO_2 emissions and the uncontrolled emissions from the utility boilers would be expected to exceed the 100 TPY major source threshold for criteria pollutants; however, neither unit would be equipped with a control device. Therefore, the boilers would not be subject to the requirements of this regulation.

UTILITY BOILERS EMISSIONS

Emissions

Expected Emissions from Utility Boilers (TPY)					
$PM_{2.5}/PM_{10}$	SO_2	NO_X	CO	VOC	Total HAPs
6.53	0.52	85.88	72.14	4.72	<0.05

ENGINE EMISSIONS

Emission Point	Description	Pollutant	Emission Limit	Regulations
CM 11.01	800 HP, Clark RA-8, 2 Stroke Clean Burn (2SCB), Propane Refrigeration/Residue Gas Compressor Engine		13, 140 Total cumulative operating hours	Rule 335-3-14-.04 (Anti-PSD Limit)
CM 11.02	800 HP, Clark RA-8, 2 Stroke Clean Burn (2SCB), Propane Refrigeration/Residue Gas Compressor Engine			
ENG-01	1,100 HP White Superior (8GTLB), Four Stoke Lean Burn (4SLB), Inlet Gas/Residue Gas Compressor Engine w/ Oxidation Catalyst	NO_X	2.0 grams/HP-Hr	Rule 335-3-14-.04 (Anti-PSD Limit)
		CO	3.75 grams/HP-Hr	Rule 335-3-14-.04 (Anti-PSD Limit)
		VOC	0.201 grams/HP-Hr	Rule 335-3-14-.04 (Anti-PSD Limit)
ENG-02	1,100 HP White Superior (8GTLB), Four Stoke Lean Burn (4SLB), Inlet Gas/Residue Gas Compressor Engine w/ Oxidation Catalyst	NO_X	3.0 grams/HP-Hr Or 250 ppmvd at 15% O_2	§60.4233(f)(4)(i) 40 CFR 60 Subpart JJJJ
		CO	4.0 grams/HP-Hr Or 540 ppmvd at 15% O_2	§60.4233(f)(4)(i) 40 CFR 60 Subpart JJJJ
		VOC	1.0 grams/HP-Hr Or 86 ppmvd at 15% O_2	§60.4233(f)(4)(i) 40 CFR 60 Subpart JJJJ

The following sections discuss the engines' applicability to state and federal regulations:

STATE REGULATIONS

Applicability:

- ADEM Admin. Code R. 335-3-4-.01, "*Visible Emissions*" for Control of Particulate Emissions would be applicable to stationary sources. The reciprocating internal combustion engines (RICE) would be subject to the requirements of this regulation.

Emission Standards:

- The engines would be required to meet the 20% and 40% opacity requirement as specified in ADEM Admin. Code R. 335-3-4-.01(1) (a) and (b).

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Compliance and Performance Test Methods and Procedures:

- Provided that visible emissions in excess of the opacity standards are observed from the engines, a visible emissions observation (VEO) shall be conducted using the methods specified in EPA Method 9 or Method 22.

Emission Monitoring:

- These units would burn natural gas as their fuel source. The expected particulate emissions from burning natural gas should be negligible; therefore, no daily opacity monitoring would be required for these units. However, if visible emissions are observed from these units in excess of the opacity standards, a VEO would be required.

Recordkeeping and Reporting Requirements:

- A record of each visible emissions observation conducted when necessary would be maintained.

Applicability:

- ADEM Admin. Code R. 335-3-14-.04 "*Prevention of Significant Deterioration (PSD) Permitting".* This regulation applies to the construction of any new major stationary source or any project at an existing major stationary source. The BEC Plant is an existing major stationary source and is considered a grandfathered source under PSD regulations. The facility's status as a grandfathered source would only change provided that a major modification has occurred. A major modification under this regulation is expected to occur if there is a significant emission increase and a significant net emissions increase as specified in ADEM Admin. Code R. 335-3-14-.04(2)(w). The project which added the two 1,100 HP, White Superior (WS), inlet gas/residue gas compressor engines to the facility did not result in a major modification because the facility placed oxidation catalysts on these two engines and they placed operating limitations on the two existing 800 HP, Clark, propane refrigeration/residue gas compressor engines.

Emission Standards:

- The total cumulative hours that the Clark engines can operate would be 13,140 hours per 12 consecutive months. This operating limit would be equivalent to running one engine continuously throughout the year and the other engine for one half of the year.

- Each WS engine should be equipped with an oxidation catalyst to reduce CO and VOC emissions by at least 50%. Of these engines, the ENG-01 engine, would be required to meet the following emission limitations to demonstrate that the oxidation catalyst reduces the emissions as proposed in the permit application:

  Nitrogen oxide (NO_X) emissions shall not exceed 2.0 grams/HP-Hr.

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Carbon monoxide (CO) emissions shall not exceed 3.75 grams/HP-Hr.

Volatile organic compounds (VOC) emissions shall not exceed 0.201 grams/HP-Hr.

Compliance and Performance Test Methods and Procedures:

- To demonstrate that the ENG-01 engine complies with its emission standards an initial compliance test shall be performed on the unit. The test shall be performed within 180 days of the unit beginning operation. Subsequent testing shall be conducted on an annual basis. The testing frequency may be modified upon Departmental approval. The following methods and procedures shall be used to conduct the compliance test:
    - 40 CFR 60 Appendix A Methods 7, 7A, 7B, 7C, 7D, 7E or other methods approved by the Department should be used to determine NO_X emissions.
    - 40 CFR 60 Appendix A Methods 10, 10A, 10B or other methods approved by the Department should be used to determine CO emissions.
    - 40 CFR 60 Appendix A Methods 18, 25, 25A, 25B, 25C, 25D, 25E or other methods approved by the Department should be used to determine VOC emissions

Emission Monitoring:

- Monitoring for the Clark engines would be in the form of maintaining records of the engine operating times.
- Monitoring for the WS engines would be in the form of maintaining the oxidation catalyst on each of the engines as required by manufacturer's specification.

Recordkeeping and Reporting Requirements:

- Engine operating hours and maintenance performed on each of the engines shall be maintained by the facility.

Applicability:

- ADEM Admin. Code R. 335-3-16-.03, "*Major Source Operating Permits".* The BEC Plant has been deemed a major source of criteria pollutants and a major source for HAP emissions. The engines located at this facility would be subject to the requirements of this regulation.

FEDERAL REGULATIONS

New Source Performance Standards (NSPS)

Applicability:

- 40 CFR 60 *Subpart A, "General Provisions"* would be subject to the ENG-02 engine since this

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engine would be subject to the applicable requirements found under 40 CFR 60, Subpart JJJJ. Table 3 of subpart JJJJ specifies which requirements under subpart A would be applicable to this unit.

Applicability:

- 40 CFR 60, Subpart JJJJ, *"Standards of Performance for Stationary Spark Ignition Internal Combustion Engines*", would be subject to the ENG-02 engine because this unit was modified after the June 12, 2006 compliance date for a reconstructed or modified engine (40 CFR §60.4230(a)(5)). According to the facility's permit application, this engine was modified in November 2007. The Clark engines would not be subject to this regulation because they were constructed prior to the compliance date for this subpart. Although, the ENG-01 engine was constructed after the compliance date for this subpart, the engine was manufactured prior to the applicable January 1, 2008 manufacture date for lean burn engines with a maximum engine power greater than or equal to 500 HP but less than 1,350 HP(40 CFR §60.4230(a)(4)(ii)). The EN-01 engine was manufactured in July 1984 and has not since been reconstructed or modified.

Emission Standards:

- To demonstrate compliance with subpart JJJJ, the ENG-02 engine must meet the following emission standards (40 CFR §60.4233(f)(4)(i)):

  - Nitrogen oxide (NO_X) emissions shall not exceed 3.0 grams/HP-Hr or 250 ppmvd at 15% O_2
  - C arbon monoxide (CO) emissions shall not exceed 4.0 grams/HP-Hr or 540 ppmvd at 15% O_2
  - Volatile organic compound (VOC) emissions shall not exceed 1.0 grams/HP-Hr Or 86 ppmvd at 15% O_2

Compliance and Performance Test Methods and Procedures:

- To demonstrate compliance with emission standards found in subpart JJJJ for the ENG-02 engine, the BEC Plant must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition an initial performance test shall be conducted within one year of the engine starting up and sequent performance testing shall be conducted every 8,760 hour or 3 years, whichever comes first, thereafter to demonstrate compliance (40 CFR §60.4243(c) and 40 §60.4243(b)(2)(ii)). Each performance test shall meet the requirements as specified in 40 CFR §60.4244. The results of each performance test must be submitted to the Department within 60 days after the test has been completed (40 CFR §60.4245(d)).

  To comply with the NO_X emission standard by limiting the concentration of NO_X in the stationary SI internal combustion engine exhaust, the following methods and procedures should be used as specified in Table 2 (a) of subpart JJJJ:

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Procedures	Method	According to the following requirements
i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005).	(a) If using a control device, the sampling site must be located at the outlet of the control device.
ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005).	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for NO_X concentration.
iii. Determine the exhaust flow rate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.	
iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for NO_X concentration.
v. Measure NO_X at the exhaust of the stationary internal combustion engine.	(5) Method 7E of 40 CFR part 60, appendix A, Method D6522–00(2005), Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(d) Results of this test consist of the average of the three 1-hour or longer run.

To comply with the CO emission standard by limiting the concentration of CO in the stationary SI internal combustion engine exhaust, the following methods and procedures should be used as specified in Table 2(b) of subpart JJJJ:

Procedures	Method	According to the following requirements
i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005).	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for CO concentration.
iii. Determine the exhaust flow rate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.	

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Procedures	Method	According to the following requirements
iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.
v. Measure CO at the exhaust of the stationary internal combustion engine.	(5) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00(2005)[a], Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17).	(d) Results of this test consist of the average of the three 1-hour or longer run.

To comply with the VOC emission standard by limiting the concentration of VOC in the stationary SI internal combustion engine exhaust, the following methods and procedures should be used as specified in Table 2(c) of subpart JJJJ:

Procedures	Method	According to the following requirements
i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3Bof 40 CFR part 60, appendix A or ASTM Method D6522–00(2005).	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for VOC concentration.
iii. Determine the exhaust flow rate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.	
iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration.
v. Measure VOC at the exhaust of the stationary internal combustion engine	(5) Methods 25A and 18 of 40 CFR part 60, appendix A, Method 25A with the use of a methane cutter as described in 40 CFR 1065.265, Method 18 or 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17).	(d) Results of this test consist of the average of the three 1-hour or longer run.

ENGINE EMISSIONS

Recordkeeping and Reporting Requirements:

- The following records shall be maintained for the ENG-02 engine as specified in §60.4245 (a):
    - All notifications submitted to comply with this subpart and all documentation supporting any notification (40 CFR §60.4245 (a)(1).
    - Maintenance conducted on the engine (40 CFR §60.4245 (a)(2))

National Emission Standards for Hazardous Air Pollutants (NESHAP)

Applicability:

- 40 CFR 63 Subpart ZZZZ covers emissions from Stationary Reciprocating Internal Combustion Engines (RICE). The requirements of Subpart ZZZZ (also referred to as the RICE MACT) would apply to any internal combustion engine that is located at a site that would be a major source of HAPs or an area source of HAPs. A major source of HAPs requires 10 TPY or more of one HAP or 25 TPY or more of a combination of HAPs (40 CFR 63.6585 (b)). An area source of HAPs under Subpart ZZZZ is defined as a source that is not a major source (40 CFR 63.6585(c)). The BEC Plant would a major source of HAPs emissions with respect to this subpart.

  An engine with a site rating of more than 500 HP located at a major source of HAPs would be considered an existing unit provided that construction or reconstruction of that unit occurred before December 19, 2002. Both Clark engines were constructed at the BEC Plant in 1977 and there is no record of reconstruction or modifications being made to these units; therefore, these units would be identified as existing units. Both WS engines were constructed at the BEC Plant after December 19, 2002; however, both were considered existing units because they were previously constructed at a gas plant in Texas which was acquired by Eagle Rock Operating Company in December 2005. According to a letter dated April 12, 2002, which was provided in the permit application for these units, one of these units were installed at the Texas plant on February 17, 2002 and the other was installed on March 16, 2002. These units were later disconnected from service and placed in storage at the Texas plant for later use.

  According to the definition of construction found in 40 CFR 63.2, construction does not include removing affected sources from an existing location and reinstalling them at another location. Therefore, moving the previously constructed units from storage in Texas to the BEC Plant would not be considered construction. Since the Clark engines and WS engines would be considered existing units, these units would not have to meet the requirements of this subpart nor the requirements of subpart A of this part and no initial notification would be necessary (40 CFR 63.6590(b)(3)(i) and (ii)). Had the WS engines been subject to this subpart when they were constructed at the Texas plant, applicability to this subpart would have followed the units to the BEC Plant.

ENGINE EMISSIONS

Compliance Assurance Monitoring

Applicability:

- 40 CFR 64, "*Compliance Assurance Monitoring (CAM)*" would be applicable to the engines provided that the engines meet all of the following criteria: be subject to an emission limit or standard, use a control device to achieve compliance with the emissions limit or standard, and have pre-controlled emissions from a regulated air pollutants that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source (40 CFR §64.2(a)).

  The two Clark engines have an operating limitation of 13,140 total cumulative hours and their uncontrolled emissions would be greater than the major source threshold for criteria pollutants; however, they would not be equipped with a control device. Therefore, these engines would not be subject to this regulation. The two WS engines would have emission limitations and they would be equipped with an oxidation catalyst; however, the uncontrolled emissions from these engines are not expected to exceed the major source threshold for criteria pollutants or for HAPs. Therefore, these engines would not be subject to the requirements of this regulation either.

Emissions

	Expected Emissions from Engines (TPY)					
Source ID	**$PM_{2.5}/PM_{10}$**	**SO_2**	**NO_X**	**CO**	**VOC**	**Total HAPs**
CM 11.01 & CM 11.02	3.42	0.066	282.10	34.35	10.66	6.99
ENG-01	0.003	0.027	21.24	39.83	2.14	2.06
ENG-02	0.003	0.027	21.24	39.83	2.14	2.06
TOTAL EXPECTED EMISSIONS	**3.426**	**0.12**	**324.58**	**114.01**	**14.94**	**11.11**

SULFUR RECOVERY UNIT/THERMAL OXIDIZER EMISSIONS

Emission Point	Description	Pollutant	Emission Limit	Regulations
Individual Sources:				
S-501 Sulfur Recovery Unit/ Thermal oxidizer				
	Beginning no later than January 1, 2013	SO_2	Less than or equal to 1,818 lb/hr based on daily 24 hour average	40 CFR§ 51.308(d)(3) 40 CFR§ 51.308(e)
		Opacity	No more than one 6 min avg. > 20%	Rule 335-3-4-.01(1)(a)
			AND	
			No 6 min avg. > 40%	Rule 335-3-4-.01(1)(b)
		H_2S	Burn gas with 0.10 grains of H_2S/scf	Rule 335-3-5-.03(1)
		H_2S	20 ppbv offsite	Rule 335-3-5-.03(2)

SULFUR RECOVERY UNIT/THERMAL OXIDIZER EMISSIONS

Emission Point	Description	Pollutant	Emission Limit	Regulations
Facility-wide Emission:				
	Available Sulfur for Category II Counties	SO_2	Depends on available sulfur	Rule 335-3-5-.03(3)
	• Available sulfur ≤ 10 LTons/Day Or	SO_2	Unlimited	
	• Available sulfur > 10 LTons/Day & ≤ 50 LTons/Day Or	SO_2	560 Lbs SO_2/Hour	
	• Available sulfur > 50 LTons/Day & ≤ 100 LTons/Day Or	SO_2	0.10 Lbs SO_2/Lb S. processed	
	• Available sulfur > 100 LTons/Day	SO_2	0.08 Lbs SO_2/ Lb S. processed	
	Allowable SO_2 emission increase relative to the H_2S content of acid gas:	SO_2	Depends on the mole percent of H_2S in Dry Acid Gas	Rule 335-3-5-.03(3)(a)
	• H_2S% in acid gas > 50% & ≤ 60% Or	SO_2	0.02 Lbs SO_2/ Lb S. processed	
	• H_2S% in acid gas > 40% & ≤ 50% Or	SO_2	0.04 Lbs SO_2/ Lb S. processed	
	• H_2S% in acid gas > 30% & ≤ 40% Or	SO_2	0.06 Lbs SO_2/ Lb S. processed	
	• H_2S% in acid gas > 20% & ≤ 30%	SO_2	0.10 Lbs SO_2/ Lb S. processed	
	• Less than 20%	SO_2	Use best available control technology	
	Natural Gas Processing Facilities in Escambia County with the capacity of greater than 50 MMscf per day of sour gas.	Total Sulfur Compounds (TSC)	Depends on available sulfur	Rule 335-3-5-.03(4)(a)
	Available Sulfur			
	• Up to 575 Ltons/Day	TSC	0.140 Lbs of Total Sulfur Compounds/ Lb of Available Sulfur	
	• 575 to 1,031 Ltons/Day	TSC	$0.186-8.57 \times 10^{-7}$ S S= lb/hr of available sulfur	
	• Over 1,031 Ltons/day	TSC	10,008 lb/hr	

The following sections explain the state and/or federal regulations the SRU/thermal oxidizer may or may not be subject to.

SULFUR RECOVERY UNIT/THERMAL OXIDIZER EMISSIONS

STATE REGULATIONS

Applicability:

- ADEM Admin. Code R. 335-3-4-.01, "*Visible Emissions"* for Control of Particulate Emissions is applicable to stationary sources. The thermal oxidizer would be subject to the requirements of this regulation.

Emission Standards:

- The thermal oxidizer is required to meet the 20% and 40% opacity requirement as specified in ADEM Admin. Code R. 335-3-4-.01(1) (a) and (b).

Compliance and Performance Test Methods and Procedures:

- Compliance with the visible emission standards shall be met by conducting a visible emission observation on the thermal oxidizer when visible emissions are observed.

Emission Monitoring:

- Opacity monitoring for the thermal oxidizer shall be conducted, according to the periodic opacity monitoring section for this unit, when visible emissions are observed. Opacity monitoring shall utilize either EPA Test Method 9 or Method 22 found in 40 CFR Part 60.

Recordkeeping and Reporting Requirements:

- Provided that visible emissions are observed from the thermal oxidizer, a record of the visible emissions observation specifying the date, time, and duration of the visible emissions and any corrective actions taken shall be maintained.

Applicability:

- ADEM Admin. Code R. 335-3-5-.03(1), "*Petroleum Production*" applies to the control of sulfur compound emissions from each petroleum production facility that handles gas or refinery gas that contains more than 0.10 grains of hydrogen sulfide (H_2S) per standard cubic foot (scf). The BEC Plant handles sour gas that contains 0.10 grain of H_2S/scf or more; therefore, the facility is subject to the applicable requirements of this regulation. The facility uses the thermal oxidizer and flares to comply with this regulation.

Emission Standards:

- In order to meet the applicability requirements of ADEM Admin. Code R. 335-3-5-.03(1), all process gas containing greater than the 0.10 grains of H_2S/scf shall be burned to the extent that the ground level concentrations of hydrogen sulfide are less than twenty (20) parts per billion beyond plant property limits, averaged over a thirty (30) minute period (ADEM Admin. Code R. 335-3-5-.03(2)). Except when being depressurized and/or

SULFUR RECOVERY UNIT/THERMAL OXIDIZER EMISSIONS

emptied, venting to the atmosphere shall not exceed 15 continuous minutes.

- SO_2 emissions from a facility designed to dispose of or process natural gas or refinery gas containing more than 0.10 grain of H_2S/scf in a Category II County depends on the available sulfur (Ltons/day) being processed and the concentration of H_2S in the acid gas stream (ADEM Admin. Code R. 335-3-5-.03(3)). The maximum available sulfur for the BEC Plant would be 550 long tons per day (Ltons/day) as specified in the facility's permit application. The permitted emission allowable for SO_2 for a plant that processes over 100 Ltons/day of available sulfur would be 0.08 pounds of SO_2 per lb of sulfur processed (lbs. SO_2/lb. S processed). This allowable would be increased to allow for dry acid gas streams containing less than 60% H_2S. The facility would be required to comply with the SO_2 emission allowable found in ADEM Admin. Code R. 335-3-5-.03(3) until January 1, 2013. After this date, the sulfur recover unit would be subject to a 1,818 lb/hr SO_2 emission limit averaged over a 24 hour period in order to comply with BART. This will further be explained in more detail in the PSD section for the SRU/TO.

- Because the BEC Plant is located in Escambia County and it is a natural gas processing plant with a design capacity of greater than 50 million standard cubic feet of sour gas per day (MMscf/day), the plant would also be subject to the requirements of ADEM Admin. Code R. 335-3-5-.04(a). The permit application indicates that the plant could process up to 68 MMscf/day. The permitted emission allowable for total sulfur compounds (TSC) for a plant that processes up to 575 Ltons/day of available sulfur would be 0.140 pounds of total sulfur compounds per lb of available sulfur (lbs. of total sulfur compounds/lb. of S).

- The total reduced sulfur (TRS) oxidation efficiency for the thermal oxidizer shall be greater than or equal to 95%. The implementation of this standard came about as the result of the September 19, 2002 consent order issued to the facility for an exceedence of the 20 ppbv offsite H_2S concentration. Air Permit No.: 502-0007-X009 was re-issued on July 7, 2003 to include this emission standard and the MSOP was modified on September 6, 2006 to include this requirement.

Compliance and Performance Test Methods and Procedures:

- Compliance with the SO_2 emission limits would be demonstrated by conducting a performance test once every 12 months for SO_2 emissions and TRS using the following methods:
  - 40 CFR 60, Appendix A, Method 1 or 1A
  - 40 CFR 60, Appendix A, Method 2, 2A, 2B, 2C, 2D, or 2E
  - 40 CFR 60, Appendix A, Method 3, 3A, 3B, or 3C
  - 40 CFR 60, Appendix A, Method 4
  - 40 CFR 60, Appendix A, Method 6, 6A, 6B, or 6C
  - 40 CFR 60, Appendix A, Method 15 or 15A
  - 40 CFR 60, Appendix A, Method 16, 16A, or 16B

- To demonstrate compliance with the 95 % TRS oxidation efficiency, the thermal oxidizer

SULFUR RECOVERY UNIT/THERMAL OXIDIZER EMISSIONS

firebox temperature would be required to be maintained at a temperature of 1,300 ^{o}F or greater. Compliance with the TRS oxidation efficiency shall also be met by calculating the efficiency based on the results of the performance test. The following calculation would be used:

$$\text{TRS oxidation efficiency \%} = \frac{[\text{ Total } SO_2 \text{ (Lbs/Hour) }] - [\text{ TRS (Lbs/Hour) }]}{\text{Total } SO_2 \text{ (Lbs/Hour)}} \times 100$$

- Compliance with the requirement to burn gas containing 0.10 grains of H_2S/scf would be demonstrated by capturing and routing the acid gas from the amine sweetening unit to the SRU and the tail gas from the SRU to the thermal oxidizer. During emergency situations, acid gas from the amine sweetening unit would be burned in the FL02 flare when the sulfur recovery plant is down or tail gas from the SRU would be burned in the FL02 flare when problems are encountered with the thermal oxidizer.

- Compliance with the requirement to maintain the ground level concentrations of hydrogen sulfide at less than twenty (20) parts per billion beyond plant property limits averaged over a thirty (30) minute period shall be met by maintaining the three hour rolling average continuous emissions monitoring system (CEMS) calculations and analysis of the sulfur recovery efficiency and/or sulfur dioxide emissions and maintaining the CEMS records of the hourly and rolling three hour average thermal oxidizer firebox temperature.

Emission Monitoring:

- The CEMS on the sulfur recovery unit shall monitor the acid gas stream entering the SRU and the acid gas stream bypassing the SRU for its volumetric flow rate and its hydrogen sulfide content. The thermal oxidizer stack shall be monitored for its volumetric flow rate and its total sulfur compound, measured as sulfur dioxide and its firebox temperature.

Recordkeeping and Reporting Requirements:

- The following records shall be maintained by the facility: record of each deviation; each performance test conducted on the SRU/thermal oxidizer; shutdown and startup records for the gas sweetening unit, the 2 stage Claus sulfur recovery unit or the thermal oxidizer; maintenance records; three hour rolling average CEMS calculations and analysis of the sulfur recovery efficiency and/or the sulfur dioxide emissions; three hour rolling average of the thermal oxidizer firebox temperature; results of each visual emission observation; and the information required by the recordkeeping section of 40 CFR 60, Subpart A and §60.647.

- A Periodic Monitoring Report (PMR) that identifies each incidence of a deviation from a permit term or condition for the SRU or thermal oxidizer, including those that occur during startups and shutdowns shall be prepared and submitted to the Department. The PMR report shall be submitted semi-annually on a calendar basis within 30 days of the end of the reporting period.

SULFUR RECOVERY UNIT/THERMAL OXIDIZER EMISSIONS

- An Excess Emissions and CMS Performance Summary report that identifies periods when there was a failure to maintain the three hour rolling SO_2 emissions or sulfur recovery efficiency at its allowable, there was a failure to maintain the three hour rolling average thermal oxidizer firebox temperature at its minimum temperature, and there was a failure for the CEMS to meet the requirements specified in 40 CFR 60 Appendix F. This report shall be submitted quarterly on a calendar basis within 30 days of the end of each reporting period.

Applicability:

- ADEM Admin. Code R. 335-3-16-.03, "*Major Source Operating Permits".* The SRU and thermal oxidizer are located at a facility that would be subject to MSOP regulations; therefore, these units shall be subject to this regulation.

Applicability:

- ADEM Admin. Code R. 335-3-14-.04 "*Prevention of Significant Deterioration (PSD) Permitting".* The BEC Plant was issued its first construction and operating permit in 1973 prior to PSD regulations being promulgated on June 19, 1978; therefore, the facility was considered a grandfathered source. In 2002, grandfathered sources were required to demonstrate compliance with PSD regulations using Best Available Retrofit Technology (BART) if they met all of the following criteria: commenced construction between August 7, 1962 and August 7, 1977, had the potential to emit 250 TPY or more of visibility-impairing air pollutants, and was listed as one of the 26 source categories under PSD that are found in 335-3-14-.04(2)(a).

  The BEC Plant commenced construction in 1973, had the potential to emit 250 TPY or more of visibility-impairing air pollutants, and was equipped with a sulfur recovery unit which was listed as one of the 26 source categories. In October 2006, the facility addressed the sulfur recovery units' applicability to BART. Through modeling, the facility was able to exempt out of BART by taking a SO_2 emission limit.

Emission Standards:

- Beginning January 1, 2013, the sulfur recovery unit shall not exceed a rolling 24 hour average SO_2 emission limit of 1,818 lb/hr (40 CFR 51.308(d)(3) and (e)).

Compliance and Performance Test Methods and Procedures:

- The existing performance test requirements for SO_2 emissions found in the facility's existing Title V permit would be sufficient to demonstrate compliance with this emission standard.

SULFUR RECOVERY UNIT/THERMAL OXIDIZER EMISSIONS

Emission Monitoring:

- The existing monitoring requirements for SO_2 emissions found in the facility's existing Title V permit would be sufficient to demonstrate compliance with this emission standard.

Recordkeeping and Reporting Requirements:

- The recordkeeping and reporting requirements for SO_2 emissions found in the facility's existing Title V permit would be sufficient to demonstrate compliance with this emission standard.

FEDERAL REGULATIONS

Compliance Assurance Monitoring

Applicability:

- 40 CFR 64, "*Compliance Assurance Monitoring (CAM)*" would be applicable to the SRU and thermal oxidizer because they would meet the applicable requirements of this regulation as follows: are subject to an emission limit or standard, use a control device to achieve compliance with the emissions limit or standard, and have pre-controlled emissions from a regulated air pollutants that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source (40 CFR §64.2(a)).

  The SRU would be used as a control device to meet the allowable sulfur dioxide emission limits based on the available sulfur rate. The pre-controlled SO_2 emissions from the SRU are expected to exceed the 100 TPY major source threshold for criteria pollutants; therefore, this unit is subject to CAM regulations.

  The thermal oxidizer would be used as control device to comply with the work practice requirement to burn process gas containing 0.10 grains of H_2S/scf. As defined in the CAM regulation, an emission limitation may be expressed in the form of a work practice, process parameter or other form of specific design. Also the pre-controlled hydrogen sulfide emissions from the thermal oxidizer are expected to exceed the 100 TPY major source threshold for criteria pollutants; therefore, this unit would be subject to CAM regulations.

  CAM monitoring for the sulfur recovery unit would be in the form of maintaining the SO_2 emission rate or sulfur recovery efficiency as required based on the available sulfur and the H_2S concentration in the acid gas stream. An annual Relative Accuracy Test Audit (RATA) would also be required to demonstrate that the continuous emission monitoring system (CEMS) on the SRU and thermal oxidizer is functioning properly.

SULFUR RECOVERY UNIT/THERMAL OXIDIZER EMISSIONS

CAM monitoring for the thermal oxidizer would be in the form of maintaining the three hour rolling average thermal oxidizer firebox temperature at greater than or equal to 1,300 ^{O}F. Initially a firebox temperature of 1350 ^{O}F was established in order to demonstrate that a 95% total reduced sulfur (TRS) destruction efficiency was met; however, the Department allowed the facility to reduce this temperature provided that they would be able to demonstrate the destruction efficiency could be met at the lower temperature.

The recordkeeping and reporting requirements of the CAM plan found in the facility's existing permit would remain unchanged. The facility would be required to submit an Excess Emissions and CMS Performance Summary Report that identifies each period in which there was a failure to maintain the three hour rolling average firebox temperature for the thermal oxidizer above or equal to 1,300 ^{o}F (or other approved minimum firebox temperature), there was a failure to maintain the three hour rolling average sulfur recovery at an efficiency within the allowable range, there was a failure to maintain the three hour rolling average sulfur dioxide emissions at a rate that is less than or equal to the SO_2 allowable, and there was a failure of the CEMS to meet the requirements specified in Appendix F of 40 CFR Part 60 while the sulfur removal system remained in operation. The report would be due quarterly on a calendar basis within 30 days of the end of the reporting period.

Emissions

Expected Emissions from SRU/Thermal Oxidizer	
Pollutant	**TPY**
$PM_{2.5}$/PM_{10}	3.52
SO_2	20,696
NO_X	46.38
CO	38.96
VOC	94.07
Total HAPs	4.44
COS	177.92
CS_2	155.68
H_2S	222.4
TRS	556

FLARE EMISSIONS

The BEC Plant consists of four flares listed below. The flares would be used along with the SRU/thermal oxidizer to control emissions from facility wide emissions sources.

Emission Point	Description	Pollutant	Emission Limit	Regulations
Individual Sources:				
FL02	**Main Process Flare**	Opacity	No Visible Emissions	§60.18(c)(1) §63.11(b)(4)
		H_2S	Burn gas with 0.10 grains of H_2S/scf	Rule 335-3-5-.03(1)
		H_2S	20 ppbv offsite	Rule 335-3-5-.03(2)
FL03	**Compressor Seal Flare**	Opacity	No Visible Emissions	§ 60.18(c)(1)
		H_2S	Burn gas with 0.10 grains of H_2S/scf	Rule 335-3-5-.03(1)
		H_2S	20 ppbv offsite	Rule 335-3-5-.03(2)
FL04	**Produced & Process Water System Flare**	Opacity	No more than one 6 min avg. > 20% AND No 6 min avg. > 40%	Rule 335-3-4-.01(1)(a) Rule 335-3-4-.01(1)(b)
		H_2S	Burn gas with 0.10 grains of H_2S/scf of gas	Rule 335-3-5-.03(1)
		H_2S	20 ppbv offsite	Rule 335-3-5-.03(2)
FL05	**Condensate Loading/Tank Flare**	Opacity	No Visible Emissions	§60.18(c)(1)
		H_2S	Burn gas with 0.10 grains of H_2S/scf of gas	Rule 335-3-5-.03(1)
		H_2S	20 ppbv offsite	Rule 335-3-5-.03(2)

FLARE EMISSIONS

Emission Point	Description	Pollutant	Emission Limit	Regulations
Facility-wide Emission Limits:				
	Available Sulfur for Category II Counties	SO_2	Depends on available sulfur	Rule 335-3-5-.03(3)
	• Available sulfur ≤ 10 LTons/Day Or	SO_2	Unlimited	
	• Available sulfur > 10 LTons/Day & ≤ 50 LTons/Day Or	SO_2	560 Lbs SO_2/Hour	
	• Available sulfur > 50 LTons/Day & ≤ 100 LTons/Day Or	SO_2	0.10 Lbs SO_2/Lb S. processed	
	• Available sulfur > 100 LTons/Day	SO_2	0.08 Lbs SO_2/ Lb S. processed	
	Allowable SO_2 emission increase relative to the H_2S content of acid gas:	SO_2	Depends on the mole percent of H_2S in Dry Acid Gas	Rule 335-3-5-.03(3)(a)
	• H_2S% in acid gas > 50% & ≤ 60% Or	SO_2	0.02 Lbs SO_2/ Lb S. processed	
	• H_2S% in acid gas > 40% & ≤ 50% Or	SO_2	0.04 Lbs SO_2/ Lb S. processed	
	• H_2S% in acid gas > 30% & ≤ 40% Or	SO_2	0.06 Lbs SO_2/ Lb S. processed	
	• H_2S% in acid gas > 20% & ≤ 30%	SO_2	0.10 Lbs SO_2/ Lb S. processed	
	• Less than 20%	SO_2	Use best available control technology	
		H_2S	Burn gas with > 0.10 grains of H_2S/scf of gas	Rule 335-3-5-.03(1)
		H_2S	20 ppbv offsite	Rule 335-3-5-.03(2)
	Natural Gas Processing Facilities in Escambia County with the capacity of greater than 50 MMscf per day of sour gas.	Total Sulfur Compounds (TSC)	Depends on available sulfur	Rule 335-3-5-.03(4)(a)
	Available Sulfur • Up to 575 Ltons/Day	TSC	0.140 Lbs of Total Sulfur Compounds/ Lb of Available Sulfur	
	• 575 to 1,031 Ltons/Day	TSC	$0.186-8.57 \times 10^{-7}$ S S= lb/hr of available sulfur	
	• Over 1,031 Ltons/day	TSC	10,008 lb/hr	

FLARE EMISSIONS

During this renewal the facility's Emergency Flare (currently designated the FL02), would be re-classified as the main process flare (FL02 or Main Flare). This flare would control the following process vapors: full well stream (FWS) vapors that occur during process upsets, pressure relief valves for sour and residue gas vapors, residue gas flaring during solar compressor downtime, acid gas flaring during sulfur recover unit downtime during upset events, off-specification residue gas, DGA propane NGL treating plant regenerator vapors, propane NGL loading vapors and TEG dehydration plant regenerator vapors. The Main Flare would also be used to control vapors from fugitive emissions from ancillary equipment and/or compressors in VHAP service. The Compressor Seal Flare (FL03) would be used to control vapors from solar compressor blowdowns and crankcase venting and from FWS vapors during meter mass balance calibrations. The Produced and Process Water System Flare (FL04) would be used to control sour hydrocarbon gas stream vapors from the saltwater treating area. The Condensate Loading/Tank Flare (FL05) would be used to control vapors from the 10,000 barrel condensate storage tank and to control fugitive vapors from the group of equipment associated with the loading rack which may be subject to 40 CFR 60, Subpart KKK.

The following sections will discuss the flares' applicability to state and/or federal regulations:

STATE REGULATIONS

Applicability:

- ADEM Admin. Code R. 335-3-4-.01, "*Visible Emissions*" for Control of Particulate Emissions would be applicable to stationary sources. Only the produced and process water system flare (FL-04) would be subject to this requirement. All other flares would be required to meet the more stringent opacity monitoring requirements specified in 40 CFR §60.18 (c)(1) or 40 CFR 63.11(b)(4).

Emission Standards:

- The FL04 flare would be required to meet the 20% and 40% opacity requirement as specified in ADEM Admin. Code R. 335-3-4-.01(1) (a) and (b).

Compliance and Performance Test Methods and Procedures:

- Compliance with the visible emission standards shall be met by conducting a daily visible emission observation of the FL04 flare utilizing EPA Test Method 9 or Method 22 found in 40 CFR Part 60.

Emission Monitoring:

- Daily opacity monitoring for the FL04 flare shall be conducted, according to the periodic opacity monitoring specified in the existing permit. No changes to this monitoring would be made during this renewal.

FLARE EMISSIONS

Recordkeeping and Reporting Requirements:

- A record of the visible emissions observation specifying the date, time, and duration of the visible emissions and any corrective actions taken shall be maintained.

Applicability:

- ADEM Admin. Code R. 335-3-5-.03(1), "*Petroleum Production*" applies to the control of sulfur compound emissions from each petroleum production facility that handles gas or refinery gas that contains more than 0.10 grains of hydrogen sulfide (H_2S) per standard cubic foot (scf) of gas. The BEC Plant handles sour gas that contains 0.10 grain of H_2S/scf of gas or more; therefore, the plant would be subject to the applicable requirements of this regulation. The facility would use the SRU/thermal oxidizer and the flares to comply with this regulation.

Emission Standards:

- In order to meet the applicability requirements of ADEM Admin. Code R. 335-3-5-.03(1), all process gas containing greater than the 0.10 grains of H_2S/scf of gas shall be burned to the extent that the ground level concentrations of hydrogen sulfide are less than twenty (20) parts per billion beyond plant property limits, averaged over a thirty (30) minute period (335-3-5-.03(2)). Except when being depressurized and/or emptied, venting to the atmosphere shall not exceed 15 continuous minutes.
  - SO_2 emissions from a facility designed to dispose of or process natural gas or refinery gas containing more than 0.10 grain of H_2S/scf of gas in a Category II County depends on the available sulfur (Ltons/day) being processed (335-3-5-.03(3)). The BEC Plant would be located in Escambia County which is a Category II County; therefore, the SO_2 emissions limits for Category II Counties found in ADEM Admin. Code R. 335-3-5-.03(3) would be applicable to this facility. The permitted SO_2 allowable for the BEC Plant would be 0.08 lbs of SO_2/lbs of S processed.
  - The allowable emissions of sulfur dioxide are increased as specified in ADEM Admin. Code R. 335-3-5-.03(3)(a) to allow for dry acid gas streams containing less than 60% H_2S.
- ADEM Admin. Code R. 335-3-5-.03(4) would be applicable to the BEC Plant because it would process natural gas that has a capacity greater than 50 million standard cubic feet of sour gas per day (50 MMscf/day) in Escambia County. The TSC allowable depends on the pounds of available sulfur. Based on the maximum design capacity, the BEC Plant could process 550 Ltons/day of available sulfur. Therefore, the TSC emissions for the BEC Plant would be limited to 0.140 pounds of TSC/pounds of available sulfur.

Compliance and Performance Test Methods and Procedures:

- Compliance with the requirement to burn gas containing 0.10 grains of H_2S/scf of gas would be demonstrated by capturing and routing sour gas or acid gas to the Main Flare. The Main Flare would be the only flare designed to combust acid gas from the sulfur recovery unit.

FLARE EMISSIONS

During periods when the SRU or thermal oxidizer would be down or when there is a process upset, acid gas could be sent to the Main Flare. All other flares would be required to burn gas containing 0.10 grains of H_2S/scf of gas; however, none of these flares would ever be expected to cause an exceedance of the SO_2 emission allowable or the TSC allowable.

- Compliance with the requirement to maintain the ground level concentrations of hydrogen sulfide at less than twenty (20) parts per billion beyond plant property limits averaged over a thirty (30) minute period shall be met by sampling and testing each process gas stream that can be sent to the Main Flare for its hydrogen sulfide content (H_2S mol%) no less than once each 12 months.

Emission Monitoring:

- Periodic monitoring to demonstrate compliance with the requirement to burn gas with more than 0.10 grains of H_2S per scf shall be met for the Main Flare by continuously monitoring the inlet assist gas and acid gas feed volume and maintaining the assist gas to acid gas volume ratio at greater than or equal to 1.0. These monitoring parameters were established, at the request of the Department, during the first Title V renewal to ensure that all gases are burned and that the offsite concentration is met. The monitoring parameters would be based on air quality modeling of combusting 100% of an acid gas stream that would result from operating the facility at a load of 400 Ltons of per day. Provided the available sulfur rates exceeds 400 Ltons/day, an air quality modeling study should be conducted to determine if the offsite H_2S concentration limit will be exceeded. If the 20 ppbv offsite hydrogen sulfide concentration limit is exceeded the facility would be required to establish a new modified indicator limit.

- Compliance with the TSC allowable would be met by continuously measuring the inlet acid gas volume and H_2S feed rate to the Main Flare which would be used to calculate the available sulfur sent to the flare and SO_2 emissions. TSC emissions shall be measured as SO_2 emissions.

Recordkeeping and Reporting Requirements:

- A record of the following shall be maintained: each deviation and corrective actions taken, the results of each visible emission observation, H_2S content (mol %) of process stream sent to the Main Flare, acid gas stream volume (Mscf/day), assist gas volume (Mscf/day), stream H_2S feed rate (Lbs/day and Lb/hr), flare H_2S feed rate (Lbs/Day), emergency flare SO_2 emissions (Lbs/day), and the number of hours Main Flare operated during the month.

- A Periodic Monitoring Report (PMR) that identifies each incidence of a deviation from a permit term or condition for all flares, including those that occur during startups and shutdowns shall be prepared and submitted to the Department. The PMR report shall be submitted semi-annually on a calendar basis within 30 days of the end of the reporting period.

- An Excess Emissions and CMS Performance Summary Report that identifies each period in which there was a failure to maintain the presence of a spark or flame at the flare tip each time process gas could have been sent to one of the flares. The report would be due semi-annually on a calendar basis within 30 days of the end of the reporting period.

FLARE EMISSIONS

Applicability:

- ADEM Admin. Code R. 335-3-16-.03, "*Major Source Operating Permits".* All the facility flares located at the BEC Plant would be subject to MSOP regulations.

FEDERAL REGULATIONS

New Source Performance Standards (NSPS)
National Emission Standards for Hazardous Air Pollutants (NESHAP)

Applicability:

The following explains the flares' applicability to NSPS and NESHAP regulations:

- FL-02, the Main Flare, would be used to comply with 40 CFR 60 Subpart KKK and 40 CFR 63, Subpart ZZZZ. 40 CFR §60.633 (g) of subpart KKK would require that a flare used to comply with the requirement of this subpart meet 40 CFR §60.18 of Subpart A, "*General Provisions*". 40 CFR §63.771(d)(1)(iii) of subpart HH would require that a flare used as a control device to reduce HAP emissions be designed and operated in accordance with the requirements of 40 CFR §63.11 (b) of Subpart A, *"General Provisions".*

- The Compressor Seal Flare (FL03) would be used to comply with 40 CFR 60, Subpart KKK to control volatile organic compound emissions from the solar compressor seals. Except that a compressor is designated for no detectable emissions, 40 CFR §63.482-3(h) exempts compressors from having to meet the monitoring requirements for compressors found in §63.482-3(a) and (b) provided that the compressor would be equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of 40 CFR §60.482-10. To comply with the control device requirements, a flare used to comply with this subpart must meet the requirements of 40 CFR §60.482-10(d) which requires that the flare comply with 40 CFR §60.18 of Subpart A, *"General Provisions*".

- The Condensate Loading/Tank Flare (FL05) would be used to comply with 40 CFR 60, Subpart K_b to control vapors from the 10,000 barrel condensate storage and to comply with 40 CFR 60, Subpart KKK to control fugitive emissions from the group of equipment associated with the loading rack. 40 CFR §60.112b(a)(3)(ii)) of subpart K_b requires that if a flare is used as a control device to reduce inlet VOC emissions by 95% or greater, the flare shall comply with the requirements of 40 CFR §60.18 of Subpart A, *"General Provisions*". 40 CFR §60.633 (g) of subpart KKK would require that a flare used to comply with the requirement of this subpart meet 40 CFR §60.18 of Subpart A, *"General Provisions*".

FLARE EMISSIONS

Emission Standards:

To demonstrate compliance with 40 CFR 60, Subpart KKK, 40 CFR 60, Subpart K_b, and 40 CFR 63, Subpart HH, the FL02, FL03, and FL05 flares shall meet the following requirements:

- Shall be designed for and operated with no visible emissions, except for a 5-minute period during any consecutive 2-hour period (40 CFR §60.18 (c)(1) and/or 40 CFR §63.11(b)(4))

  - Method 22 of Subpart 60 Appendix A shall be used to determine compliance with this requirement. The observation period is 2 hours and shall be used according to Method 22 (40 CFR §60.18 (f)(1), 40 CFR §63.11(b)(4), 40 CFR §60.113b(d), 40 CFR §63.772(e)(2)(i), and 40 CFR §60.485(g)(1)).

- Shall be operated with a flame present at all times (40 CFR §60.18 (c)(2) and/or 40 CFR §63.11(b)(5))

  - The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame (40 CFR §60.18 (f)(2) , 40 CFR §63.11(b)(5), 40 CFR §60.485(g)(2),and 40 CFR §60.113b(d)).

- Shall be steam-assisted, air-assisted, or nonassisted (40 CFR §60.18 (c)(6) and/or 40 CFR §63.11(b)(2))

- Shall adhere to either the heat content specifications found in §63.11(b)(6)(ii) for Subpart HH (§60.18 (c)(3)(ii) for Subpart KKK or K_b) and the maximum tip velocity specifications in §63.11(b)(7) or (b)(8) for Subpart HH (§60.18 (c)(4) for Subpart KKK or K_b) or the requirements of §63.11(b)(6)(i) for Subpart HH (§60.18 (c)(3)(i) for Subpart KKK or K_b) as specified in either 40 §63.11(b)(6)) for Subpart HH or 40 CFR §60.18 (c)(3) for Subpart KKK or K_b

  - The net heating value of gas being combusted in a flare would be determined as specified in 40 CFR §60.18 (f)(3), 40 CFR §63.11(b)(6)(ii), and 40 CFR §60.485(g)(4)

  - The actual exit velocity of the flare would be determined as specified in 40 CFR §60.18(f)(4), 40 CFR §63.11(b)(7)(i), and 40 CFR §60.485(g)(1)

  - The maximum permitted velocity for steam-assisted and nonassisted flares would be determined as specified in 40 CFR §60.18 (f)(5) and 40 CFR §63.11(b)(7)(iii)

  - The maximum permitted velocity for air assisted flares would be determined as specified in 40 CFR §60.18 (f)(6), 40 CFR §63.11(b)(8), and 40 CFR §60.485(g)(3)

FLARE EMISSIONS

- o Shall be monitored to ensure that they are operated and maintained in conformance with their designs (40 CFR §60.18(d), 40 CFR §63.11(b)(1), and 40 CFR §60.486(d)(3))

- o Shall be operated at all times when emissions may be vented to them (40 CFR §60.18 (e), 40 CFR §63.11(b)(3), 40 CFR §63.771(d)(4), 40 CFR §60.482-10(m) and 40 CFR §60.113b(d))

Compliance and Performance Test Methods and Procedures:

- Compliance with the visible emission standards for the FL02, FL03, and FL05 flares shall be met by conducting a daily visible emission observation of these flare as specified in the opacity monitoring section of the existing permit. Opacity monitoring shall utilize EPA Test Method 22.

Emission Monitoring:

- Opacity monitoring for the FL02, FL03, and FL05 flares shall be performed using EPA Test Method 22 of 40 CFR Part 60 as outlined in the monitoring plan specified in the Appendix of the existing permit.

Recordkeeping and Reporting Requirements:

- Except when the FL02, FL03, and FL05 flares are not operating, a record of daily visible emission observations shall be maintained.

- Records shall be kept of all periods of operation during which the flare pilot flame is absent (40 CFR §60.115b(d)(2) and 40 CFR §60.486(d)(4))

- Dates of startup and shutdowns of the closed vent system and control device (40 CFR §60.486(d)(5))

- Semi-annual reports of all periods in which the pilot flame was absent shall be submitted to the Department (40 CFR §60.115b(d)(3)).

Compliance Assurance Monitoring

Applicability:

- 40 CFR 64, "*Compliance Assurance Monitoring (CAM)*" would be applicable to the Main Flare since it would meet the applicable requirements of this regulation as follows: have an emission limit or standard, use a control device to achieve compliance with the emission limit or standard, and have pre-controlled emissions from a regulated air pollutants that are equal to or greater than 100 percent of the amount, in tons per year, required for a source

FLARE EMISSIONS

to be classified as a major source (40 CFR §64.2(a)).

All facility flares would be used as a control device to comply with the work practice requirement to burn process gas containing 0.10 grains of H_2S/scf established by the state. As defined in this subpart, an emission limitation or standard may be expressed in the form of a work practice, process or control parameter or other form of specific design, equipment, operational or operation and maintenance requirement (40 CFR §64.1). A regulated pollutant under ADEM Admin. Code R. 335-3-16-.01(w)(3) would include H_2S since this pollutant would be subject to a standard promulgated under Section 111 (covering New Source Performance Standards) of the Clean Air Act.

Only the pre-controlled hydrogen sulfide emissions from the Main Flare would be expected to exceed the 100 TPY major source threshold for a regulated air pollutant; therefore, this unit would be subject to CAM regulations. The other flares would not be subject to CAM because the H_2S emissions would not be expected to exceed 100 TPY; however, periodic monitoring for these flares would follow the same monitoring plan as the CAM plan. The one exception to this plan would be that a Quality Improvement Plan (QIP) would not be required for the FL03, FL04, or FL05 flares.

The flares would demonstrate compliance with its applicable monitoring plan by maintaining the presence of a flame or spark at the flare tip at all times when a process gas stream may be sent to it. A visual inspection of the flare for the presence of a flame or spark at the flare tip would be conducted daily if a continuous sparking flame igniter or continuous burning pilot light would not be used.

Record keeping demonstrating compliance with flares applicable monitoring plan shall be kept as specified in the facility's existing permit.

Emissions

	Expected Emissions from Flares (TPY)					
Source ID	**$PM_{2.5}/PM_{10}$**	**SO_2**	**NO_X**	**CO**	**VOC**	**Total HAPs**
FL02	0.043	5.903	1.582	8.61	22.524	0.103
FL03	0.01	0.01	0.09	0.50	0.09	0.05
FL04	0.01	0.01	0.01	0.02	0.01	0.05
FL05	0.57	8.76	12.03	24.01	19.16	1.69
TOTAL EXPECTED EMISSIONS	**0.633**	**14.683**	**13.712**	**33.14**	**41.784**	**1.893**

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STORAGE TANK EMISSIONS

The following storage tanks are located at the BEC Plant:

Emission Point	Description	Pollutant	Emission Limit	Regulations
Individual Sources:				
(T101A)- 211,506 Gallon Condensate Vertical Fixed Roof Storage Tanks		VOC		§60.110(a) 40 CFR 60, Subpart K
(T101B)- 211,506 Gallon Condensate Vertical Fixed Roof Storage Tanks		VOC		§60.110(a) 40 CFR 60, Subpart K
(T101C)- 211,506 Gallon Condensate Vertical Fixed Roof Storage Tanks		VOC		§60.110(a) 40 CFR 60, Subpart K
(T101D)- 420,000 Gallon Condensate Vertical Fixed Roof Storage Tanks		VOC		§60.110b(a) 40 CFR 60, Subpart K_b
211,506 Gallon Salt-Water Vertical Fixed Roof Storage Tanks				

The following sections would discuss the applicability of the storage tanks to federal regulations.

FEDERAL REGULATIONS

New Source Performance Standards (NSPS)

Applicability:

40 CFR 60 Subpart K, "*Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced after June 11, 1973 and Prior to May 19, 1978*", would be subject to the three 5,000 barrel condensate storage tanks located at the BEC Plant. Construction permits were issued for the BEC Plant on September 4, 1973. The three 5,000 barrel (210,000 gallons) condensate storage tanks were included in the permit application for the sulfur recovery plant and the process heat boilers; however, a permit was not issued specifically for these tanks.

Affected facilities under this subpart would be each storage vessel petroleum liquids which has a storage capacity greater than 40,000 gallons (40 CFR §60.110(a)). Any storage vessel that has a capacity greater than 65,000 gallons and commences construction or modification after June 11, 1973 and prior to May 19, 1978 would be subject to the applicable requirements of this subpart (40 CFR §60.110(c)(2)).

The facility has been incorrectly exempt from the requirements of this subpart based on the assumption that custody transfer had not occurred prior to the condensate being stored at the BEC Plant; however, based on the definition of custody transfer found in 40 CFR §60.111

STORAGE TANK EMISSIONS

the condensate would be stored after custody transfer (40 CFR §60.110(b)). Custody transfer does not take into consideration ownership; therefore, exemption from this subpart would not be applicable.

Emission Standards:

- Since the true vapor pressure of the petroleum liquid stored in the 5000 barrel storage tanks would be greater than or equal to 1.5 psia but less than 11.1 psia, in order to meet the VOC emission standard the storage vessel shall be equipped with a floating roof, a vapor recovery system or their equivalents (40 CFR §60.112(a)(1)). The condensate stored in these tanks would have an average true vapor pressure of 6.36 psia as specified in Tile V permit renewal application. Currently the facility maintains a residue gas blanket over the stored condensate. Periodically venting to atmosphere occurs as the volume of condensate fluctuates inside of the tank

  Currently the three 5,000 barrel storage tanks are not equipped with a control device to meet the control requirements of this subpart. However, the facility has proposed to install a closed vent system to route vapors for these tanks to a NSPS flare in order to comply with this subpart.

Emission Monitoring:

- Monitoring of operations shall be met by maintaining the records as specified in the recordkeeping and reporting requirement section.

Recordkeeping and Reporting Requirements:

- Unless the facility equips the storage tanks with a vapor recovery and return or disposal system in accordance with the requirements of 40 CFR §60.112, the BEC Plant must maintain the following records (40 CFR §60.113(a)):

  - Record of the petroleum liquid stored
  - Period of storage
  - Maximum true vapor pressure of that liquid during the respective storage period

Applicability:

- 40 CFR 60 Subpart K_b, *"Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced after June 23, 1984"*, would be subject to the 10,000 barrel condensate storage tank (T101D). The anticipated construction date for this tank would be the end of 2010. This tank would have a capacity greater than or equal to 75 cubic meter (m^3)(or 471.7358 barrels of oil) and it would be used to store

STORAGE TANK EMISSIONS

volatile organic liquids (VOL) after custody transfer; therefore, it would not meet the exemption specified in 40 CFR §60.110b(d)(4).

Emission Standards:

- Because the maximum true vapor pressure for the condensate stored in the T101D tank would be greater than or equal to 76.6 kilopascals (kPa) (or 11.11 psia), this tank shall be equipped with either a closed vent system (CVS) and control device as specified in §60.112b(a)(3) of this subpart (40 CFR §60.112b(b)(1)) or equipped with a system equivalent to a closed vent system and a control device as provided in §60.114b of this subpart (40 CFR §60.112b(b)(2)). The BEC Plant would use a closed vent system and a NSPS flare to comply with the subpart.

  - The closed vent system must meet the following requirements (40 CFR §60.112b(a)(3)(i)):

    - Be designed to collect all volatile organic compounds (VOC) vapors and gases discharged from the storage vessel

    - Be operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV §60.485(b)

  - The control device must meet the following requirements (40 CFR §60.112b(a)(3)(ii)):

    - Be designed and operated to reduce inlet VOC emissions by 95 percent or greater

    - If a flare is used it shall meet the specifications described in 40 CFR 60.18

Compliance and Performance Test Methods and Procedures:

- EPA Test Method 21 shall be used to determine no detectable emissions from the closed vent system as specified in §60.485(c) of 60 Subpart VV (§60.112b(a)(3)(i))

- EPA Method 22 shall be used to determine visible emissions from the flare used to control emissions from this storage tank as specified in §60.113b(d)

Emission Monitoring:

- Monitoring would be in the form of maintaining records for the closed vent system and flare.

STORAGE TANK EMISSIONS

Recordkeeping and Reporting Requirements:

- The records specified in 40 CFR §60.115b(d)) shall be maintained to demonstrate compliance with this subpart.

- All records required under 40 CFR §60.116b shall be maintained for at least 2 years, except that records showing the dimensions of the storage vessel and any analysis showing the capacity of the storage vessel shall be readily accessible for the life of the source (40 CFR §60.116b(b)).

Emissions

	Expected Emissions from Storage Tanks (TPY)	
Source ID	**VOC**	**Total HAPs**
T101A, B, & C	125.81	9.47
T101D	0.0	0.0
TOTAL EXPECTED EMISSIONS	125.81	9.47

Recommendations

I recommend that Escambia Operating Company, LLC be issued its second Title V Renewal of Major Source Operating Permit No. 502-0007 for the Big Escambia Creek Oil and Gas Production, Treating, and Processing Facility. The facility should be able to meet the applicable state and federal regulations associated with each emission source.

______________________________ December 14, 2010
Harlotte M. Bolden-Wright Draft Date
Industrial Minerals Section
Energy Branch
Air Division

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ATTACHMENT A

DRAFT PROVISOS

MAJOR SOURCE OPERATING PERMIT

PERMITTEE: Escambia Operating Company, LLC

FACILITY NAME: Big Escambia Creek Gas Production, Treating and Processing Facility

FACILITY/PERMIT NO.: 502-0007

LOCATION: 3888 Sardis Church Road

Atmore, Escambia County, Alabama

In accordance with and subject to the provisions of the Alabama Air Pollution Control Act of 1971, as amended, Ala. Code 1975, §§22-28-1 to 22-28-23 (2006 Rplc. Vol. and 2007 Cum. Supp.) (the "AAPCA") and the Alabama Environmental Management Act, as amended, Ala. Code 1975, §§22-22A-1 to 22-22A-15, (2006 Rplc. Vol. and 2007 Cum. Supp.) and rules and regulations adopted thereunder, and subject further to the conditions set forth in this permit, the Permittee is hereby authorized to construct, install and use the equipment, device or other article described above.

Pursuant to the ***Clean Air Act of 1990****, all conditions of this permit are federally enforceable by EPA, the Alabama Department of Environmental Management, and citizens in general. Those provisions which are not required under the* ***Clean Air Act of 1990*** *are considered to be state permit provisions and are not federally enforceable by EPA and citizens in general. Those provisions are contained in separate sections of this permit.*

Issuance Date: DRAFT 12/14/2010

Effective Date:

Expiration Date: *January 7, 2016*

Alabama Department of Environmental Management

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1. Transfer	
This permit is not transferable, whether by operation of law or otherwise, either from one location to another, from one piece of equipment to another, or from one person to another, except as provided in Rule 335-3-16-.13(1)(a)5.	Rule 335-3-16-.02(6)
2. Renewals	
An application for permit renewal shall be submitted at least six (6) months, but not more than eighteen (18) months, before the date of expiration of this permit. The source for which this permit is issued shall lose its right to operate upon the expiration of this permit unless a timely and complete renewal application has been submitted within the time constraints listed in the previous provision.	Rule 335-3-16-.12(2)
3. Severability Clause	
The provisions of this permit are declared to be severable and if any section, paragraph, subparagraph, subdivision, clause, or phrase of this permit shall be adjudged to be invalid or unconstitutional by any court of competent jurisdiction, the judgment shall not affect, impair, or invalidate the remainder of this permit, but shall be confined in its operation to the section, paragraph, subparagraph, subdivisions, clause, or phrase of this permit that shall be directly involved in the controversy in which such judgment shall have been rendered.	Rule 335-3-16-.05(e)
4. Compliance	
(a) The permittee shall comply with all conditions of ADEM Admin. Code 335-3. Noncompliance with this permit will constitute a violation of the Clean Air Act of 1990 and ADEM Admin. Code 335-3 and may result in an enforcement action; including but not limited to, permit termination, revocation and reissuance, or modification; or denial of a permit renewal application by the permittee.	Rule 335-3-16-.05(f)
(b) The permittee shall not use as a defense in an enforcement action that maintaining compliance with conditions of this permit would have required halting or reducing the permitted activity.	Rule 335-3-16-.05(g)

General Permit Provisos

Federally Enforceable Provisos	Regulations
5. Termination for Cause	
This permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance will not stay any permit condition.	Rule 335-3-16-.05(h)
6. Property Rights	
The issuance of this permit does not convey any property rights of any sort, or any exclusive privilege.	Rule 335-3-16-.05(i)
7. Submission of Information	
The permittee must submit to the Department, within 30 days or for such other reasonable time as the Department may set, any information that the Department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or to determine compliance with this permit. Upon receiving a specific request, the permittee shall also furnish to the Department copies of records required to be kept by this permit.	Rule 335-3-16-.05(j)
8. Economic Incentives, Marketable Permits, and Emissions Trading	
No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit.	Rule 335-3-16-.05(k)
9. Certification of Truth, Accuracy, and Completeness:	
Any application form, report, test data, monitoring data, or compliance certification submitted pursuant to this permit shall contain certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.	Rule 335-3-16-.07(a)

General Permit Provisos

Federally Enforceable Provisos	Regulations
10. <u>Inspection and Entry</u>	
Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized representatives of the Alabama Department of Environmental Management and EPA to conduct the following:	Rule 335-3-16-.07(b)
(a) Enter upon the permittee's premises where a source is located or emissions-related activity is conducted, or where records must be kept pursuant to the conditions of this permit;	
(b) Review and/or copy, at reasonable times, any records that must be kept pursuant to the conditions of this permit;	
(c) Inspect, at reasonable times, this facility's equipment (including monitoring equipment and air pollution control equipment), practices, or operations regulated or required pursuant to this permit;	
(d) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this permit or other applicable requirements.	
11. <u>Compliance Provisions</u>	
(a) The permittee shall continue to comply with the applicable requirements with which the company has certified that it is already in compliance.	Rule 335-3-16-.07(c)
(b) The permittee shall comply in a timely manner with applicable requirements that become effective during the term of this permit.	
12. <u>Compliance Certification</u>	
On or before March 9 of each year, a compliance certification shall be submitted.	Rule 335-3-16-.07(e)
(a) The compliance certification shall include the following:	
(1) The identification of each term or condition of this permit that is the basis of the certification;	

General Permit Provisos

Federally Enforceable Provisos | **Regulations**

(2) The compliance status;

(3) The method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with Rule 335-3-16-.05(c) (Monitoring and Record Keeping Requirements);

(4) Whether compliance has been continuous or intermittent;

(5) Such other facts as the Department may require to determine the compliance status of the source.

(b) The compliance certification shall be submitted to :

Alabama Department of Environmental Management
Air Division
P.O. Box 301463
Montgomery, AL 36130-1463

and to:

Air and EPCRA Enforcement Branch
EPA Region IV
61 Forsyth Street, SW
Atlanta, GA 30303

13. <u>Reopening for Cause</u>

Under any of the following circumstances, this permit will be reopened prior to the expiration of the permit:

Rule 335-3-16-.13(5)

(a) Additional applicable requirements under the Clean Air Act of 1990 become applicable to the permittee with a remaining permit term of three (3) or more years. Such a reopening shall be completed not later than eighteen (18) months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which this permit is due to expire.

(b) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into this permit.

Federally Enforceable Provisos	Regulations
(c) The Department or EPA determines that this permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of this permit.	
(d) The Administrator or the Department determines that this permit must be revised or revoked to assure compliance with the applicable requirements.	
14. <u>Additional Rules and Regulations</u>	
This permit is issued on the basis of Rules and Regulations existing on the date of issuance. In the event additional Rules and Regulations are adopted, it shall be the permit holder's responsibility to comply with such rules.	§22-28-16(d), <u>Code of Alabama 1975</u>, as amended
15. <u>Equipment Maintenance or Breakdown</u>	
(a) In the case of shutdown of air pollution control equipment (which operates pursuant to any permit issued by the Director) for necessary scheduled maintenance, the intent to shut down such equipment shall be reported to the Director at least twenty-four (24) hours prior to the planned shutdown, unless such shutdown is accompanied by the shutdown of the source which such equipment is intended to control. Such prior notice shall include, but is not limited to the following:	Rule 335-3-1-.07(1), (2)
(1) Identification of the specific facility to be taken out of service as well as its location and permit number;	
(2) The expected length of time that the air pollution control equipment will be out of service;	
(3) The nature and quantity of emissions of air contaminants likely to occur during the shutdown period;	
(4) Measures such as the use of off-shift labor and equipment that will be taken to minimize the length of the shutdown period;	
(5) The reasons that it would be impossible or impractical to shut down the source operation during the maintenance period.	

General Permit Provisos

Federally Enforceable Provisos	Regulations
(b) In the event that there is a breakdown of equipment or upset of process in such a manner as to cause, or is expected to cause, increased emissions of air contaminants which are above an applicable standard, the person responsible for such equipment shall notify the Director within 24 hours or the next working day and provide a statement giving all pertinent facts, including the estimated duration of the breakdown. The Director will be notified when the breakdown has been corrected.	
16. <u>Operation of Capture and Control Devices</u>	
All air pollution control devices and capture systems for which this permit is issued shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.	§22-28-16(d), <u>Code of Alabama 1975</u>, as amended
17. <u>Obnoxious Odors</u>	
This permit is issued with the condition that, should obnoxious odors arising from the plant operations be verified by Air Division inspectors, measures to abate the odorous emissions shall be taken upon a determination by the Alabama Department of Environmental Management that these measures are technically and economically feasible.	Rule 335-3-1-.08
18. <u>Fugitive Dust</u>	
(a) Precautions shall be taken to prevent fugitive dust emanating from plant roads, grounds, stockpiles, screens, dryers, hoppers, ductwork, etc.	Rule 335-3-1-.02
(b) Plant or haul roads and grounds will be maintained in the following manner so that dust will not become airborne:	
(1) By the application of water any time the surface of the road is sufficiently dry to allow the creation of dust emissions by the act of wind or vehicular traffic;	
(2) By reducing the speed of vehicular traffic to a point below that at which dust emissions are created;	

Federally Enforceable Provisos	Regulations
(3) By paving;	
(4) By the application of binders to the road surface at any time the road surface is found to allow the creation of dust emissions;	
Should one, or a combination, of the above methods fail to adequately reduce airborne dust from plant or haul roads and grounds, alternative methods shall be employed, either exclusively or in combination with one or all of the above control techniques, so that dust will not become airborne. Alternative methods shall be approved by the Department prior to utilization.	
19. <u>Additions and Revisions</u>	
Any modifications to this source shall comply with the modification procedures in Rules 335-3-16-.13 or 335-3-16-.14.	Rule 335-3-16-.13 and .14
20. <u>Recordkeeping Requirements</u>	
(a) Records of required monitoring information of the source shall include the following:	Rule 335-3-16-.05(c)(2)
(1) The date, place, and time of all sampling or measurements;	
(2) The date analyses were performed;	
(3) The company or entity that performed the analyses;	
(4) The analytical techniques or methods used;	
(5) The results of all analyses; and	
(6) The operating conditions that existed at the time of sampling or measurement.	

Federally Enforceable Provisos	Regulations
(b) Retention of records of all required monitoring data and support information of the source for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation and copies of all reports required by the permit	
21. <u>Reporting Requirements</u>	
(a) Reports to the Department of any required monitoring shall be submitted at least every 6 months. All instances of deviations from permit requirements must be clearly identified in said reports. All required reports must be certified by a responsible official consistent with Rule 335-3-16-.04(9).	Rule 335-3-16-.05(c)(3)
(b) Deviations from permit requirements shall be reported within 48 hours or 2 working days of such deviations, including those attributable to upset conditions as defined in the permit. The report will include the probable cause of said deviations, and any corrective actions or preventive measures that were taken.	
22. <u>Emission Testing Requirements</u>	
Each point of emission which requires testing will be provided with sampling ports, ladders, platforms, and other safety equipment to facilitate testing performed in accordance with procedures established by Part 60 of Title 40 of the Code of Federal Regulations, as the same may be amended or revised.	Rule 335-3-1-.05(3) & Rule 335-3-1-.04(1)
The Air Division must be notified in writing at least 10 days in advance of all emission tests to be conducted and submitted as proof of compliance with the Department's air pollution control rules and regulations.	
To avoid problems concerning testing methods and procedures, the following shall be included with the notification letter:	

General Permit Provisos

Federally Enforceable Provisos	Regulations
(a) The date the test crew is expected to arrive, the date and time anticipated of the start of the first run, how many and which sources are to be tested, and the names of the persons and/or testing company that will conduct the tests.	Rule 335-3-1-.04
(b) A complete description of each sampling train to be used, including type of media used in determining gas stream components, type of probe lining, type of filter media, and probe cleaning method and solvent to be used (if test procedures require probe cleaning).	
(c) A description of the process(es) to be tested including the feed rate, any operating parameters used to control or influence the operations, and the rated capacity.	
(d) A sketch or sketches showing sampling point locations and their relative positions to the nearest upstream and downstream gas flow disturbances.	
A pretest meeting may be held at the request of the source owner or the Air Division. The necessity for such a meeting and the required attendees will be determined on a case-by-case basis.	Rule 335-3-1-.04
All test reports must be submitted to the Air Division within 30 days of the actual completion of the test unless an extension of time is specifically approved by the Air Division.	
23. <u>Payment of Emission Fees</u>	
Annual emission fees shall be remitted each year according to the fee schedule in ADEM Admin. Code R. 335-1-7-.04.	Rule 335-1-7-.04
24. <u>Other Reporting and Testing Requirements</u>	
Submission of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require emission testing at any time.	Rule 335-3-1-.04(1)

General Permit Provisos

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25. **Title VI Requirements (Refrigerants)**	
Any facility having appliances or refrigeration equipment, including air conditioning equipment, which use Class I or Class II ozone-depleting substances as listed in 40 CFR Part 82, Subpart A, Appendices A and B, shall service, repair, and maintain such equipment according to the work practices, personnel certification requirements, and certified recycling and recovery equipment specified in 40 CFR Part 82, Subpart F.	40 CFR Part 82
No person shall knowingly vent or otherwise release any Class I or Class II substance into the environment during the repair, servicing, maintenance, or disposal of any device except as provided in 40 CFR Part 82, Subpart F.	
The responsible official shall comply with all reporting and recordkeeping requirements of 40 CFR 82.166. Reports shall be submitted to the US EPA and the Department as required.	
26. **Chemical Accidental Prevention Provisions**	
If a chemical listed in Table 1 of 40 CFR Part 68.130 is present in a process in quantities greater than the threshold quantity listed in Table 1, then:	40 CFR Part 68
(a) The owner or operator shall comply with the provisions in 40 CFR Part 68.	
(b) The owner or operator shall submit one of the following:	
(1) A compliance schedule for meeting the requirements of 40 CFR Part 68 by the date provided in 40 CFR Part 68 § 68.10(a) or,	
(2) A certification statement that the source is in compliance with all requirements of 40 CFR Part 68, including the registration and submission of the Risk Management Plan.	
27. **Display of Permit**	
This permit shall be kept under file or on display at all times at the site where the facility for which the permit is issued is located and will make the permit readily available for inspection by any or all persons who may request to see it.	Rule 335-3-14-.01(1)(d)

General Permit Provisos

Federally Enforceable Provisos	Regulations
28. Circumvention	
No person shall cause or permit the installation or use of any device or any means which, without resulting in the reduction in the total amount of air contaminant emitted, conceals or dilutes any emission of air contaminant which would otherwise violate the Division 3 rules and regulations.	Rule 335-3-1-.10
29. Visible Emissions	
Unless otherwise specified in the Unit Specific provisos of this permit, any source of particulate emissions shall not discharge more than one 6-minute average opacity greater than 20% in any 60-minute period. At no time shall any source discharge a 6-minute average opacity of particulate emissions greater than 40%. Opacity will be determined by 40 CFR Part 60, Appendix A, Method 9, unless otherwise specified in the Unit Specific provisos of this permit.	Rule 335-3-4-.01(1)
30. Fuel-Burning Equipment	
Unless otherwise specified in the Unit Specific provisos of this permit, no fuel-burning equipment may discharge particulate emissions in excess of the emissions specified in Part 335-3-4-.03.	Rule 335-3-4-.03
Unless otherwise specified in the Unit Specific provisos of this permit, no fuel-burning equipment may discharge sulfur dioxide emissions in excess of the emissions specified in Part 335-3-5-.01.	Rule 335-3-5-.01
31. Process Industries – General	
Unless otherwise specified in the Unit Specific provisos of this permit, no process may discharge particulate emissions in excess of the emissions specified in Part 335-3-4-.04.	Rule 335-3-4-.04
32. Averaging Time for Emission Limits	
Unless otherwise specified in the permit, the averaging time for the emission limits listed in this permit shall be the nominal time required by the specific test method.	Rule 335-3-1-.05
33. Compliance Assurance Monitoring (CAM)	
Conditions (a) through (d) that follow are general conditions applicable to emissions units that are subject to the CAM requirements. Specific requirements related to each emissions unit are contained in the unit specific provisos and the attached CAM appendices.	

General Permit Provisos

Federally Enforceable Provisos	Regulations
(a) Operation of Approved Monitoring (1) *Commencement of operation.* The owner or operator shall conduct the monitoring required under this section and detailed in the unit specific provisos and CAM appendix of this permit (if required) upon issuance of the permit, or by such later date specified in the permit pursuant to §64.6(d). (2) *Proper maintenance.* At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment. (3) *Continued operation.* Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.	40 CFR 64.7

Federally Enforceable Provisos	Regulations
(4) *Response to excursions or exceedances*. (a) Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable. (b) Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.	

General Permit Provisos

Federally Enforceable Provisos	Regulations
(5) *Documentation of need for improved monitoring.* After approval of monitoring under this part, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Department and, if necessary, submit a proposed modification to the permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.	
(b) Quality Improvement Plan (QIP) Requirements	40 CFR 64.8
(1) Based on the results of a determination made under Section 33(a)(4)(b) above, the Administrator or the permitting authority may require the owner or operator to develop and implement a QIP. Consistent with 40 CFR §64.6(c)(3), the permit may specify an appropriate threshold, such as an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, for requiring the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices.	
(2) Elements of a QIP:	
(i) The owner or operator shall maintain a written QIP, if required, and have it available for inspection.	

Federally Enforceable Provisos	Regulations
(ii) The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:	
(I) *Improved preventive maintenance practices.*	
(II) *Process operation changes.*	
(III) *Appropriate improvements to control methods.*	
(IV) *Other steps appropriate to correct control performance.*	
(V) *More frequent or improved monitoring (only in conjunction with one or more steps under paragraphs (2)(b)(i) through (iv) above).*	
(3) If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Department if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.	
(4) Following implementation of a QIP, upon any subsequent determination pursuant to Section 33(a)(4)(b) above, the Department may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:	
(i) Failed to address the cause of the control device performance problems; or	
(ii) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.	

(5) Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(c) Reporting and Recordkeeping Requirements — 40 CFR 64.9

(1) General reporting requirements

(i) On and after the date specified in Section 33(a)(1) above by which the owner or operator must use monitoring that meets the requirements of this part, the owner or operator shall submit monitoring reports to the permitting authority in accordance with ADEM Admin. Code R. 335-3-16-.05(c)3.

(ii) A report for monitoring under this part shall include, at a minimum, the information required under ADEM Admin. Code R. 335-3-16-.05(c)3. and the following information, as applicable:

(I) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(II) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

Federally Enforceable Provisos	Regulations
(III) A description of the actions taken to implement a QIP during the reporting period as specified in Section 33(b) above. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.	
(2) General recordkeeping requirements.	
(i) The owner or operator shall comply with the recordkeeping requirements specified in ADEM Admin. Code R. 335-3-16-.05(c)2.. The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to Section 33(b) above and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).	
(ii) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.	
(d) Savings Provisions	40 CFR 64.10
(1) Nothing in this part shall:	

General Permit Provisos

Federally Enforceable Provisos	Regulations
(i) Excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. The requirements of this part shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purpose of determining the monitoring to be imposed under separate authority under the Act, including monitoring in permits issued pursuant to title I of the Act. The purpose of this part is to require, as part of the issuance of a permit under title V of the Act, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of this part. (ii) Restrict or abrogate the authority of the Department to impose additional or more stringent monitoring, recordkeeping, testing, or reporting requirements on any owner or operator of a source under any provision of the Act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable. (iii) Restrict or abrogate the authority of the Department to take any enforcement action under the Act for any violation of an applicable requirement or of any person to take action under section 304 of the Act.	

Summary Page for 97 MMBtu/hr Utility Boilers

Permitted Operating Schedule: **24** Hours/Day x **365** Days/Year = **8760** Hours/Year

Emission Limitations:

Emission Point	Description	Pollutant	Emission Limit	Regulations
(B0301A)	**97 MMBtu/Hour, Natural Gas-Fired, Utility Boiler (No. 1 Steam Plant South Boiler)**	PM	0.21 Lbs/ MMBTU of heat input	Rule 335-3-4-.03(2)
		SO_2	4 Lbs/MMBTU of heat input	Rule 335-3-5-.01(1)(b)
		NO_X	NONE	
		VOC	NONE	
		CO	NONE	
		Opacity	No more than one 6 min avg. > 20% AND	Rule 335-3-4-.01(1)(a)
			No 6 min avg. > 40%	Rule 335-3-4-.01(1)(b)
(B0301B)	**97 MMBtu/Hour, Natural Gas-Fired, Utility Boiler (No. 1 Steam Plant North Boiler)**	PM	0.21 Lbs/ MMBTU of heat input	Rule 335-3-4-.03(2)
		SO_2	4 Lbs/MMBTU of heat input	Rule 335-3-5-.01(1)(b)
		NO_X	NONE	
		VOC	NONE	
		CO	NONE	
		Opacity	No more than one 6 min avg. > 20% AND	Rule 335-3-4-.01(1)(a)
			No 6 min avg. > 40%	Rule 335-3-4-.01(1)(b)
(B01301A)	**97 MMBtu/Hour, Natural Gas-Fired, Utility Boiler (No. 2 Steam Plant South Boiler)**	PM	0.21 Lbs/ MMBTU of heat input	Rule 335-3-4-.03(2)
		SO_2	4 Lbs/MMBTU of heat input	Rule 335-3-5-.01(1)(b)
		NO_X	NONE	
		VOC	NONE	
		CO	NONE	
		Opacity	No more than one 6 min avg. > 20% AND	Rule 335-3-4-.01(1)(a)
			No 6 min avg. > 40%	Rule 335-3-4-.01(1)(b)
(B01301B)	**97 MMBtu/Hour, Natural Gas-Fired, Utility Boiler (No. 2 Steam Plant North Boiler)**	PM	0.21 Lbs/ MMBTU of heat input	Rule 335-3-4-.03(2)
		SO_2	4 Lbs/MMBTU of heat input	Rule 335-3-5-.01(1)(b)
		NO_X	NONE	
		VOC	NONE	
		CO	NONE	
		Opacity	No more than one 6 min avg. > 20% AND	Rule 335-3-4-.01(1)(a)
			No 6 min avg. > 40%	Rule 335-3-4-.01(1)(b)

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Provisos for Utility Boilers

Federally Enforceable Provisos	Regulations
Applicability	
1. Each utility boiler shall be subject to the requirements of ADEM Admin. Code R. 335-3-4-.01, "*Visible Emissions*" and the requirements specified in this subpart of this permit.	Rule 335-3-4-.01(1)
2. Each utility boiler shall be subject to the requirements of ADEM Admin. Code R. 335-3-4-.03(2), "*Fuel Burning Equipment*" and the requirements specified in this subpart of this permit.	Rule 335-3-4-.03(2)
3. Each utility boiler shall be subject to the requirements of ADEM Admin. Code R. 335-3-5-.01(1)(b), "*Fuel Combustion*" and the requirements specified in this subpart of this permit.	Rule 335-3-5-.01(1)(b)
4. Each utility boiler shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-16, "*Major Source Operating Permits*" and the requirements specified in this subpart of this permit.	Rule 335-3-16-.03
Emissions Standards	
1. Each utility boiler shall comply with the following requirements:	Rule 335-3-14-.04
(a) Except for one 6-minute period during any 60-consecutive minute period, a boiler shall not discharge into the atmosphere particulate that results in opacity greater than 20%, as determined by a 6-minute average.	Rule 335-3-4-.01(1)(a)
(b) At no time shall a boiler discharge into the atmosphere particulate that results in opacity greater than 40%, as determined by a 6-minute average.	Rule 335-3-4-.01(1)(b)
(c) Particulate emissions shall not exceed [{3.109} X { (MMBtu of heat input)$^{-0.589}$] Lbs of PM per MMBtu of heat input.	Rule 335-3-4-.03(2)
(d) Sulfur dioxide emissions shall not exceed 4.0 Lbs of SO_2 per MMBtu of heat input.	Rule 335-3-5-.01(1)(b)

Provisos for Utility Boilers

Federally Enforceable Provisos	Regulations
Compliance and Performance Test Methods and Procedures	
1. The fuel gas shall be tested for its heat content and hydrogen sulfide (H_2S) content in accordance to the requirements specified in proviso 1(a) through (d) of this section of this subpart.	Rule 335-3-16-.05(c)(1)(i)
(a) Heat content and H_2S content testing shall consist of capturing a representative sample of the fuel gas stream at a frequency of no less than once each twelve (12) months.	
(b) The sample shall be analyzed for its heat content by utilizing the ASTM Analysis Method D1826-77 or equivalent method. [Fuel Heat Content (Btu/Scf)]	
(c) The sample shall be analyzed for its hydrogen sulfide content by utilizing the Tutwiler procedures found in 40 CFR §60.648 or the chromatographic analysis procedures found in ASTM E-260 or the stain tube procedures found in GPA 2377-86 or those provided by the stain tube manufacture. [Fuel H_2S Content (ppmv)]	
(d) The frequency of analysis may be modified upon receiving Departmental approval.	
Emission Monitoring	
1. Emission monitoring to demonstrate compliance with the SO_2 emissions limit would be in the form of maintaining records as required in the *recordkeeping and reporting* section of this subpart of this permit.	Rule 335-3-16-.05(c)(1)
Recordkeeping and Reporting Requirements	
1. A record of the information specified in provisos 1(a) through (e) of this section of this subpart shall be maintained and made available for inspection.	Rule 335-3-16-.05(c)(2)
(a) The date, starting time and duration of each deviation from the requirements specified in this subpart along with the cause and corrective actions taken.	
(b) Date and type of boiler maintenance that affects air emissions	

Provisos for Utility Boilers

Federally Enforceable Provisos | **Regulations**

(c) Fuel gas heat content

[Fuel Heat Content (Btu/Scf)]

(d) Fuel gas hydrogen sulfide content

[Fuel H_2S Content (ppmv)]

(e) Lbs SO_2/MMBTU =

$$\frac{[\text{Fuel } H_2S \text{ (ppmv)}] \times [0.1684]}{\text{Fuel Heat Content (Btu/Scf)}}$$

Where, the Fuel Gas H_2S Content (ppmv) and Fuel Gas Heat Content [Btu/Scf] shall be equal to the results of the most recent fuel gas analysis conducted

2. Monitoring reports meeting the requirements specified in proviso 2(a) and (b) of this section of this subpart shall be submitted to the Department.

Rule 335-3-16-.05(c)(2)
Rule 335-3-16-.05(c)(3)(i)

(a) Each report shall identify each incidence of deviation from a permit term or condition including those that occur during startups and shutdowns.

(1) A deviation shall mean any condition determined by observation, by data derived from any monitoring or testing or recordkeeping which is required by the permit that can be used to determine or indicate compliance, that identifies an affected source has failed to meet an applicable emission limit or standard or that a work practice was not complied with or completed.

(2) If no deviation event occurred during the reporting period, a statement that indicates there were no deviations from the permit requirements shall be included in the report.

(b) A Periodic Monitoring Report (PMR) meeting the requirements specified in provisos 2(b)(1) through (3) of this section of this subpart shall be submitted to the Department.

(1) A deviation shall consist of, but is not limited to, any period time during which the following occurs:

Federally Enforceable Provisos	Regulations
(i) There was a failure to burn fuel which would result in emissions of less than or equal to 4 Lbs. of SO_2 per MMBtu of heat input.	
(ii) There was a failure to burn natural gas as fuel.	
(iii) There was a failure to meet the requirements specified in the *compliance and performance test methods and procedures* section of this subpart.	
(iv) There was a failure to meet the requirements specified in the *emission monitoring* section of this subpart.	
(v) There was a failure to meet the requirements specified in the *recordkeeping and reporting requirements* section of this subpart.	
(vi) There was a failure to take immediate corrective actions when a deviation occurred.	
(2) Except as provided for in proviso 2(c) of this section, the report shall meet the requirements specified in proviso 2(b)(2)(i) of this section of this subpart.	
(i) For each deviation event, the following information shall be submitted.	
(I) *Emission source description*	
(II) *Permit requirement*	
(III) *Date*	
(IV) *Starting time*	
(V) *Duration*	
(VI) *Actual quantity of pollutant or parameter*	
(VII) *Cause*	

Provisos for Utility Boilers

Federally Enforceable Provisos	Regulations

(VIII) *Actions taken to return to normal operating conditions*

(IX) *Total operating hours of the affected source during the reporting period*

(X) *Total hours of deviation events during the reporting period*

(XI) *Total hours of deviation events that occurred during start ups, shut downs, and malfunctions during the reporting period*

(3) Each report shall cover a calendar semi-annual period and shall be submitted using the following reporting schedule:

Reporting Period	**Submittal Date**
January 1st through June 30th	July 31st
July 1st through December 31st	January 31st

(c) The report content specified in proviso 2(b) of this section may be modified upon receipt of Departmental approval.

3. Each deviation from the requirements specified in this subpart, including those that occur during startups, shutdowns, and malfunctions, shall be reported to the Department in a manner that complies with proviso 15(b) and 21(b) of the general proviso subpart of this permit.	Rule 335-3-16-.05(c)(2) Rule 335-3-16-.05(c)(3)(ii)

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Summary Page for ENG-02 Gas Compressor Engine

Permitted Operating Schedule: **24** Hours/Day x **365** Days/Year = **8760** Hours/Year

Emission Limitations:

Emission Point	Description	Pollutant	Emission Limit	Regulations
ENG-02	1,100 HP White Superior (8GTLB), Four Stoke Lean Burn (4SLB), Inlet Gas/Residue Gas Compressor Engine w/ Oxidation Catalyst	NO_X	3.0 grams/HP-Hr Or 250 ppmvd at 15% O_2	§60.4233(f)(4)(i) 40 CFR 60 Subpart JJJJ
		CO	4.0 grams/HP-Hr Or 540 ppmvd at 15% O_2	§60.4233(f)(4)(i) 40 CFR 60 Subpart JJJJ
		VOC	1.0 grams/HP-Hr Or 86 ppmvd at 15% O_2	§60.4233(f)(4)(i) 40 CFR 60 Subpart JJJJ

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Provisos for ENG-02 Gas Compressor Engine

Federally Enforceable Provisos	Regulations
Applicability	
1. The ENG-02 engine shall be subject to the requirements of ADEM Admin. Code R. 335-3-4-.01, "*Visible Emissions*" and the requirements specified in this subpart of this permit.	Rule 335-3-4-.01(1)
2. The ENG-02 engine shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-16, "*Major Source Operating Permits*" and the requirements specified in this subpart of this permit.	Rule 335-3-16-.03
3. The ENG-02 engine shall be subject to the requirements of 40 CFR 60 Subpart A, "*General Provisions*" as specified in Table 3 of 40 CFR 60 Subpart JJJJ.	Table 3 40 CFR 60, Subpart JJJJ
4. The ENG-02 engine shall be subject to the requirements of 40 CFR 60, Subpart JJJJ, *"Standards of Performance for Stationary Spark Ignition Internal Combustion Engines*" and the requirements specified in this subpart of this permit.	§60.4230(a)(5)
Emissions Standards	
1. The ENG-02 engine shall meet the following opacity standards:	Rule 335-3-4-.01(1)
(a) Except for one 6-minute period during any 60-minute period, the engine shall not discharge into the atmosphere particulate that results in an opacity greater than 20%, as determined by a 6-minute average.	Rule 335-3-4-.01(1)(a)
(b) At no time shall the engine discharge into the atmosphere particulate that results in an opacity greater than 40%, as determined by a 6-minute average.	Rule 335-3-4-.01(1)(b)
2. To demonstrate compliance with the emission standards found in 40 CFR 60, Subpart JJJJ, the ENG-02 engine shall meet the following emission standards for the entire life of the engine:	§60.4234 §60.4233(f)(4)(i)
(a) Nitrogen oxide (NO_X) emissions shall not exceed 3.0 grams/HP-Hr (7.28 Lbs./Hr) or 250 ppmvd at 15% O_2	
(b) Carbon monoxide (CO) emissions shall not exceed 4.0 grams/HP-Hr (9.70 Lbs./Hr) or 540 ppmvd at 15% O_2	
(c) Volatile organic compound (VOC) emissions shall not exceed 1.0 grams/HP-Hr (2.43 Lbs/Hr) Or 86 ppmvd at 15% O_2	

Provisos for ENG-02 Gas Compressor Engine

Federally Enforceable Provisos	Regulations
Compliance and Performance Test Methods and Procedures	
1. The compliance requirements under subpart JJJJ requires that a maintenance plan and records of conducted maintenance be kept and that, to the extent practicable, the engine shall be maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions.	§60.4243(c) §60.4243(b)(2)(ii)
2. To demonstrate compliance with the testing requirements for subpart JJJJ, performance testing shall be conducted as follows:	
(a) An initial performance testing shall be conducted within one year of engine startup to demonstrate compliance.	§60.4243(b)(2)(ii)
(b) Each performance test must meet the requirements specified in §60.4244 (a) through (f) and as specified in provisos 2(b)(1) through (3) of this section of this subpart.	§60.4244 §60.8
(1) To comply with the NO_X emission standard by limiting the concentration of NO_X in the stationary SI internal combustion engine exhaust, the following methods and procedures shall be used:	Table 2 (a) 40 CFR 60, Subpart JJJJ
(i) Method 1 or 1A of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)	
(ii) Method 3, 3A, or 3B of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)	
(iii) Method 2 or 19 of 40 CFR part 60	
(iv) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17)	
(v) Method 7E of 40 CFR part 60, appendix A, Method D6522–00(2005), Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17)	

Provisos for ENG-02 Gas Compressor Engine

Federally Enforceable Provisos			Regulations
(2)	To comply with the CO emission standard by limiting the concentration of CO in the stationary SI internal combustion engine exhaust, the following methods and procedures shall be used:		Table 2 (b) 40 CFR 60, Subpart JJJJ
	(i)	Method 1 or 1A of 40 CFR part 60, appendix A	
	(ii)	Method 3, 3A, or 3B of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)	
	(iii)	Method 2 or 19 of 40 CFR part 60	
	(iv)	Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17)	
	(v)	Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00(2005), Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	
(3)	To comply with the VOC emission standard by limiting the concentration of VOC in the stationary SI internal combustion engine exhaust, the following methods and procedures shall be used:		Table 2 (c) 40 CFR 60, Subpart JJJJ
	(i)	Method 1 or 1A of 40 CFR part 60, appendix A	
	(ii)	Method 3, 3A, or 3B of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)	
	(iii)	Method 2 or 19 of 40 CFR part 60	
	(iv)	Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17)	

Provisos for ENG-02 Gas Compressor Engine

Federally Enforceable Provisos	Regulations
(v) Methods 25A and 18 of 40 CFR part 60, appendix A, Method 25A with the use of a methane cutter as described in 40 CFR 1065.265, Method 18 or 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03 (incorporated by reference, see §60.17)	
(c) Subsequent performance testing shall occur every 8,760 hours or 3 years, whichever comes first.	§60.4243(b)(2)(ii)
(d) Copy of each performance test shall be submitted within 60 days after the test has been completed.	§60.4245(d)
Emission Monitoring	
1. Emission monitoring to demonstrate compliance with subpart JJJJ would be in the form of maintaining records as required in the *record keeping and reporting* section of this subpart of this permit.	
Record Keeping and Reporting Requirements	
1. The following records shall be maintained for the ENG-02 engine:	
(a) All notifications submitted to comply with this subpart and all documentation supporting any notification	§60.4245 (a)(1) §60.19
(b) Maintenance conducted on the engine	§60.4245 (a)(2)
(c) Records specified in §60.4245 (a)(3) and (4) where applicable.	§60.4245 (a)(3) & (a)(4)
(d) Engine Fuel Gas Consumption [Fuel Gas Volume (MScf/Month)	
(e) Engine Operating Hours [Op Hour (Hours/Month)	
(f) NO_X, CO, and VOC Emissions [Emissions (Lbs./Hr)] *Obtained from the most recent performance test.*	

Summary Page for Miscellaneous Gas Compressor Engines

Permitted Operating Schedule: **24** Hours/Day x **365** Days/Year = **8760** Hours/Year

Emission Limitations:

Emission Point	Description	Pollutant	Emission Limit	Regulations
ENG-01	1,100 HP White Superior (8GTLB), Four Stoke Lean Burn (4SLB), Inlet Gas/Residue Gas Compressor Engine w/ Oxidation Catalyst	NO_X	2.0 grams/HP-Hr	Rule 335-3-14-.04 (Anti-PSD Limit)
		CO	3.75 grams/HP-Hr	Rule 335-3-14-.04 (Anti-PSD Limit)
		VOC	0.201 grams/HP-Hr	Rule 335-3-14-.04 (Anti-PSD Limit)

Permitted Operating Schedule: **13,140** Total Hours/12 Consecutive Months

Emission Limitations:

Emission Point	Description	Pollutant	Emission Limit	Regulations
CM 11.01	800 HP, Clark RA-8, 2 Stroke Clean Burn (2SCB), Propane Refrigeration/Residue Gas Compressor Engine		13,140 Total cumulative operating hours	Rule 335-3-14-.04 (Anti-PSD Limit)
CM 11.02	800 HP, Clark RA-8, 2 Stroke Clean Burn (2SCB), Propane Refrigeration/Residue Gas Compressor Engine			

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Provisos for Miscellaneous Gas Compressor Engines

Federally Enforceable Provisos	Regulations
Applicability	
1. The ENG-01, CM 11.01, and CM 11.02 engines shall be subject to the requirements of ADEM Admin. Code R. 335-3-4-.01, "*Visible Emissions*" and the requirements specified in this subpart of this permit.	Rule 335-3-4-.01(1)
2. The ENG-01, CM 11.01, and CM 11.02 engines have emission limitations that allow them to be a synthetic minor source when determining applicability to the requirements of ADEM Admin. Code R. 335-3-14-.04, "*Prevention of Significant Deterioration*" and the requirements specified in this subpart of this permit.	Rule 335-3-14-.04
3. The ENG-01, CM 11.01, and CM 11.02 engines shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-16, "*Major Source Operating Permits*" and the requirements specified in this subpart of this permit.	Rule 335-3-16-.03
Emissions Standards	
1. The ENG-01, CM 11.01, and CM 11.02 engines shall meet the following opacity standards:	Rule 335-3-4-.01(1)
(a) Except for one 6-minute period during any 60-minute period, the engine shall not discharge into the atmosphere particulate that results in an opacity greater than 20%, as determined by a 6-minute average.	Rule 335-3-4-.01(1)(a)
(b) At no time shall the engine discharge into the atmosphere particulate that results in an opacity greater than 40%, as determined by a 6-minute average.	Rule 335-3-4-.01(1)(b)
2. The total cumulative operating hours for the CM 11.01 and CM 11.02 engines shall not exceed 13,140 hours per twelve consecutive months.	Rule 335-3-14-.04 Anti-PSD Limits
3. The ENG-01 engine shall be equipped with an oxidation catalyst and shall meet the following emissions limitations:	Rule 335-3-14-.04 Anti-PSD Limits
(a) Nitrogen Oxide (NO_X) emissions shall not exceed 2.0 grams/HP-Hr (or 4.85 Lbs/Hr)	
(b) Carbon Monoxide (CO) emissions shall not exceed 3.75 grams/HP-Hr (or 9.10 Lbs/Hr)	

Provisos for Miscellaneous Gas Compressor Engines

Federally Enforceable Provisos	Regulations
(c) Volatile Organic Compounds (VOC) emissions shall not exceed 0.201 grams/HP-Hr (0.49 Lbs/Hr)	
Compliance and Performance Test Methods and Procedures	
1. The fuel gas shall be tested for its heat content (Btu/Scf) in accordance to the following requirements:	Rule 335-3-16-.05(c)(1)(i) Rule 335-3-1-.05
(a) Heat content testing shall occur at a frequency of no less than once every six (6) months.	
(b) Each sample shall be analyzed for its heat content by utilizing the ASTM Analysis Method D1826-77 or equivalent method. [Fuel Heat Content (BTU/Scf)]	
(c) The frequency of analysis may be modified upon Departmental approval.	
2. To demonstrate that the oxidation catalyst is efficiently reducing emissions from the ENG-01 engine, the following testing requirements must be met:	
(a) An initial compliance test shall be performed within 180 days of the engine commencing operation.	
(b) The following methods shall be used to demonstrate compliance with the emissions standards:	
(1) For NO_X emissions, Methods 7, 7A, 7B, 7C, 7D, 7E of 40 CFR 60 Appendix A or other methods approved by the Department	
(2) For CO emissions, Methods 10, 10A, 10B of 40 CFR 60 Appendix A or other methods approved by the Department	
(3) For VOC emissions, Methods 18, 25, 25A, 25B, 25C, 25D, 25E of 40 CFR 60 Appendix A or other methods approved by the Department	
(c) Subsequent compliance tests shall be performed no less than once each twelve months.	
(d) Compliance test reports shall be submitted within 30 days of the test date.	

Provisos for Miscellaneous Gas Compressor Engines

Federally Enforceable Provisos	Regulations
(e) The frequency of testing and report submittal may be modified upon Departmental approval.	
Emission Monitoring	Rule 335-3-16-.05(c)(1)
1. Monitoring for the CM 11.01 and CM 11.02 engines would be in the form of maintaining records.	
2. Monitoring for the ENG-01 engine would be in the form of maintaining the oxidation catalyst on the engines as required by manufacturer's specification.	
Record Keeping and Reporting Requirements	
1. The following records shall be maintained for all miscellaneous engines:	
(a) The date, starting time and duration of each deviation from the requirements specified in this subpart along with the cause and corrective actions taken.	
(b) Date and type of engine maintenance that affects air emissions	
(c) Engine Fuel Gas Consumption [Fuel Volume (MScf/Month)	
(d) Engine Fuel Gas Heat Content [Fuel Heat Content (Btu/Scf)]	
(e) Engine Operating Hours [Op Hour (Hours/Month)]	
2. The following records shall be maintained for the CM 11.01 and CM 11.02 engines:	
(a) Total Cumulative Operating Hours [Total Hours (Hours/12 Consecutive Months)]	
3. The following records shall be maintained for the ENG-01 engine:	
(a) Test Emissions Factors for NO_X, CO, and VOC	

Federally Enforceable Provisos | **Regulations**

[Test EF (Lbs/MMBtu)]

Obtained from the most recent performance test for each pollutant.

(b) Fuel Gas Heat Input

[Heat Input (MMBtu/Hr)]

Obtained from most recent gas analysis

(c) NO, CO, and VOC Emissions (Lbs/Hr) =

Test EF (Lb/MMBtu) X Heat Input (MMBtu/Hr)

4. Monitoring reports meeting the requirements specified in proviso 4(a) through (c) of this section of this subpart shall be submitted to the Department.

Rule 335-3-16-.05(c)(2)
Rule 335-3-16-.05(c)(3)(i)

(a) Each report shall identify each incidence of deviation from a permit term or condition including those that occur during startups and shutdowns.

(1) A deviation shall mean any condition determined by observation, by data derived from any monitoring or testing or recordkeeping which is required by the permit that can be used to determine or indicate compliance, that identifies an affected source has failed to meet an applicable emission limit or standard or that a work practice was not complied with or completed.

(2) If no deviation event occurred during the reporting period, a statement that indicates there were no deviations from the permit requirements shall be included in the report.

(b) A Periodic Monitoring Report (PMR) meeting the requirements specified in provisos 4(b)(1) through (3) of this section of this subpart shall be submitted to the Department.

(1) A deviation shall consist of, but is not limited to, any period of time during which the following occurs:

(i) There was a failure to meet the opacity standards for the engines.

Federally Enforceable Provisos	Regulations
(ii) There was a failure to maintain the total operating hours for the CM 11.01 and CM 11.02 engines at less than 13,140 hours per 12 consecutive months.	
(iii) There was a failure to maintain NO_X, CO, and VOC emissions from the ENG-01 engine below the allowables specified in the *emissions standards* section of this subpart.	
(iv) There was a failure to meet the requirements specified the *compliance and performance test methods and procedures* section of this subpart.	
(v) There was a failure to meet the requirements specified in the *emission monitoring* section of this subpart.	
(vi) There was a failure to meet the requirements specified in the *recordkeeping and reporting requirements* section of this subpart.	
(vii) There was a failure to take immediate corrective actions when a deviation occurred.	
(2) Except as provided for in proviso 4(c) of this section, the report shall meet the requirements specified in proviso 4(c)(2)(i) of this section of this subpart.	
(i) For each deviation event, the following information shall be submitted.	
(I) *Emission source description*	
(II) *Permit requirement*	
(III) *Date*	
(IV) *Starting time*	
(V) *Duration*	

Provisos for Miscellaneous Gas Compressor Engines

Federally Enforceable Provisos	Regulations
(VI) *Actual quantity of pollutant or parameter*	
(VII) *Cause*	
(VIII) *Actions taken to return to normal operating conditions*	
(IX) *Total operating hours of the affected source during the reporting period*	
(X) *Total hours of deviation events during the reporting period*	
(XI) *Total hours of deviation events that occurred during start ups, shut downs, and malfunctions during the reporting period*	
(3) Each report shall cover a calendar semi-annual period and shall be submitted using the following reporting schedule:	
(4)	
(c) The report content specified in proviso 4(b) of this section may be modified upon receipt of Departmental approval.	
5. Each deviation from the requirements specified in this subpart, including those that occur during startups, shutdowns, and malfunctions, shall be reported to the Department in a manner that complies with proviso 15(b) and 21(b) of the general proviso subpart of this permit.	Rule 335-3-16-.05(c)(2) Rule 335-3-16-.05(c)(3)(ii)

Reporting Period	**Submittal Date**
January 1st through June 30th	July 31st
July 1st through December 31st	January 31st

Summary Page for Sulfur Recovery Unit & Thermal Oxidizer

Permitted Operating Schedule: **24** Hours/Day x **365** Days/Year = **8760** Hours/Year

Emission Limitations:

Emission Point	Description	Pollutant	Emission Limit	Regulations
Individual Sources:				
Sulfur Recovery Unit				
Beginning no later than January 1, 2013		SO_2	Less than or equal to 1,818 lb/hr based on daily 24 hour average	40 CFR§ 51.308(d)(3) 40 CFR§ 51.308(e)
F-501 Thermal Oxidizer		Opacity	No more than one 6 min avg. > 20%	Rule 335-3-4-.01(1)(a)
			AND No 6 min avg. > 40%	Rule 335-3-4-.01(1)(b)
		H_2S	Burn gas with 0.10 grains of H_2S/scf	Rule 335-3-5-.03(1)
		H_2S	20 ppbv offsite	Rule 335-3-5-.03(2)

Emission Limitations (Con't):

Emission Point	Description	Pollutant	Emission Limit	Regulations
Facility-wide Emission Limitations:				
	Available Sulfur for Category II Counties	SO_2	Depends on available sulfur	Rule 335-3-5-.03(3)
	• Available sulfur $\leq$ 10 LTons/Day Or	SO_2	Unlimited	
	• Available sulfur > 10 LTons/Day & $\leq$ 50 LTons/Day Or	SO_2	560 Lbs SO_2/Hour	
	• Available sulfur > 50 LTons/Day & $\leq$ 100 LTons/Day Or	SO_2	0.10 Lbs SO_2/Lb S. processed	
	• Available sulfur > 100 LTons/Day	SO_2	0.08 Lbs SO_2/ Lb S. processed	
	Allowable SO_2 emission increase relative to the H_2S content of acid gas:	SO_2	Depends on the mole percent of H_2S in Dry Acid Gas	Rule 335-3-5-.03(3)(a)
	• H_2S% in acid gas > 50% & $\leq$ 60% Or	SO_2	0.02 Lbs SO_2/ Lb S. processed	
	• H_2S% in acid gas > 40% & $\leq$ 50% Or	SO_2	0.04 Lbs SO_2/ Lb S. processed	
	• H_2S% in acid gas > 30% & $\leq$ 40% Or	SO_2	0.06 Lbs SO_2/ Lb S. processed	
	• H_2S% in acid gas > 20% & $\leq$ 30%	SO_2	0.10 Lbs SO_2/ Lb S. processed	
	• Less than 20%	SO_2	Use best available control technology	
	Natural Gas Processing Facilities in Escambia County with the capacity of greater than 50 MMscf per day of sour gas.	Total Sulfur Compounds (TSC)	Depends on available sulfur	Rule 335-3-5-.03(4)(a)
	Available Sulfur			
	• Up to 575 Ltons/Day	TSC	0.140 Lbs of Total Sulfur Compounds/ Lb of Available Sulfur	
	• 575 to 1,031 Ltons/Day	TSC	$0.186-8.57 \times 10^{-7}$ S S= lb/hr of available sulfur	
	• Over 1,031 Ltons/day	TSC	10,008 lb/hr	

Provisos for SRU and Thermal Oxidizer

Federally Enforceable Provisos	Regulations
Applicability	
1. The thermal oxidizer shall be subject to the requirements of ADEM Admin. Code R. 335-3-4-.01, "*Visible Emissions*" and the requirements specified in this subpart of this permit.	Rule 335-3-4-.01(1)
2. The BEC Plant shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-5-.03(1), "*Petroleum Production*" and the requirements specified in this subpart of this permit. The sulfur recovery unit/ thermal oxidizer and flares shall be used to comply with this regulation.	Rule 335-3-5-.03(1)
3. The BEC Plant shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-5-.03(4) and the requirements specified in this subpart of this permit.	Rule 335-3-5-.03(4)
4. The sulfur recovery unit and thermal oxidizer shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-16, "*Major Source Operating Permits*" and the requirements specified in this subpart of this permit.	Rule 335-3-16-.03
5. The sulfur recovery unit with thermal oxidizer has limits in place in order to avoid a review under the 40 CFR 51.308(e).	40 CFR 51.308(d)(3) 40 CFR 51.308(e)
6. The sulfur recovery unit and thermal oxidizer shall be subject to the requirements specified in 40 CFR Part 64, "*Compliance Assurance Monitoring (CAM)*" as indicated in proviso 33 of the *General Permit Provisos* subpart and in this subpart of this permit.	40 CFR Part 64
Emissions Standards	
1. The thermal oxidizer shall meet the following opacity standards:	Rule 335-3-4-.01(1)
(a) Except for one 6-minute period during any 60-minute period, the engine shall not discharge into the atmosphere particulate that results in an opacity greater than 20%, as determined by a 6-minute average.	Rule 335-3-4-.01(1)(a)
(b) At no time shall the engine discharge into the atmosphere particulate that results in an opacity greater than 40%, as determined by a 6-minute average.	Rule 335-3-4-.01(1)(b)

Provisos for SRU and Thermal Oxidizer

Federally Enforceable Provisos | **Regulations**

2. Except as is provided for in proviso 2(a) of this section of this subpart, each process gas stream containing more than 0.10 of a grain of hydrogen sulfide per Scf shall not be emitted into the atmosphere unless it is properly burned to maintain the ground level concentrations of hydrogen sulfide to less than twenty (20) parts per billion beyond plant property limits, averaged over a thirty (30) minute period.

   (a) Provided vessels or equipment are being de-pressured and/or emptied and the reduced pressure will not allow flow of the process gas stream to the combustion device, the venting to the atmosphere of any gas stream shall be allowed, but the duration of the venting shall not exceed 15 continuous minutes.

Rule 335-3-5-.03(2)

3. Sulfur dioxide (SO_2) emissions from the BEC Plant, which depend on the amount of available sulfur processed, shall not exceed the following allowables:

Available Sulfur (Long Tons/Day)	Permitted Emissions of SO_2
Up to 10	No Limit
10 to 50	560 lbs/hour
50 to 100	0.10 lbs. SO_2/lb. S processed
Over 100	0.08 lbs. SO_2/lb. S processed

Rule 335-3-5-.03(3)

4. The allowable emissions of sulfur dioxide, specified in proviso 3 of this section of this subpart, are increased as follows to allow for dry acid gas streams containing less than 60 percent hydrogen sulfide (H_2S):

Mole Percent of Hydrogen Sulfide In Dry Acid Gas (mol % H_2S)	Additional SO_2 Emissions Allowed
50% but less than 60%	0.02 lbs. SO_2/lb. S processed
40% but less than 50%	0.04 lbs. SO_2/lb. S processed
30% but less than 40%	0.06 lbs. SO_2/lb. S processed
20% but less than 30%	0.10 lbs. SO_2/lb. S processed
Less than 20%	Must utilize the best available control technology, with consideration to the technical practicability and economic reasonableness of reducing or eliminating the emissions from the facility.

Rule 335-3-5-.03(3)(a)

Provisos for SRU and Thermal Oxidizer

Federally Enforceable Provisos | **Regulations**

5. Total sulfur compound (TSC) emissions from the BEC Plant, measured as sulfur dioxide, shall not exceed the following allowables depending on the available sulfur:

Rule 335-3-5-.03(4)(a)

Available Sulfur (Long Tons/Day)	Permitted Emissions of Total Sulfur Compounds
Up to 575	0.140 pounds of total sulfur compounds per pound of available sulfur
575 to 1031	Pounds of total sulfur compounds per pound of available sulfur = $0.186 - 8.57 \text{ X } 10^{-7}\mathbf{S}$ where **S** = lb/hr of available sulfur
Over 1031	10,008 lb/hr

6. Beginning no later than January 1, 2013, SO_2 emissions from the sulfur recovery unit/thermal oxidizer shall not exceed 1,818 Lbs of SO_2/Hr while utilizing a daily 24 hour average of the data measured and calculated each calendar day.

40 CFR 51.308(d)(3)
40 CFR 51.308(e)

7. The thermal oxidizer's total reduce sulfur (TRS) oxidation efficiency shall be equal to or greater than 95.0%.

Added as a result of the September 19, 2002 Consent Order

Compliance and Performance Test Methods and Procedures

1. If visible emissions in excess of the opacity standards are observed from the thermal oxidizer, a visible emission observation utilizing EPA Test Method 9 or Method 22 shall be conducted.

Rule 335-3-4-.01(2)

2. A performance test shall be conducted in accordance to the requirements specified as follows:

Rule 335-3-16-.05(c)(1)(i)
Rule 335-3-1-.05

   (a) At lease once every twelve (12) months

   (b) Consist of three runs of at least 1-hour in duration each.

      (1) Each run shall test for the emissions of SO_2 and TRS.

      (2) Each run shall be conducted in accordance to the appropriate reference methods and procedures specified in the following sections of this subpart.

         (i) 40 CFR Part 60 Appendix A, Method 1 or 1A

Provisos for SRU and Thermal Oxidizer

Federally Enforceable Provisos	Regulations
(ii) 40 CFR Part 60 Appendix A, Method 2 or 2A or 2B or 2C or 2D or 2E	
(iii) 40 CFR Part 60 Appendix A, Method 3 or 3A or 3B or 3C	
(iv) 40 CFR Part 60 Appendix A, Method 4	
(v) 40 CFR Part 60 Appendix A, Method 6 or 6A or 6B or 6C	
(vi) 40 CFR Part 60 Appendix A, Method 15 or 15A	
(vii) 40 CFR Part 60 Appendix A, Method 16 or 16A or 16B	
(3) TRS oxidation efficiency % = $\frac{[\text{ Total } SO_2 \text{ (Lbs/Hour) }] - [\text{ TRS (Lbs/Hour) }]}{\text{Total } SO_2 \text{ (Lbs/Hour)}}$	
(4) The pollutants tested for and the methods and procedures that are utilized may be modified upon receiving Departmental approval.	
Emission Monitoring	
1. Compliance Assurance Monitoring (CAM) for the Sulfur Recovery Unit and Thermal Oxidizer shall be met as specified in *Appendix A* of this permit.	§64.6(b) & (c) Rule 335-3-16-.05(c)(1)
2. Except during times that the production facility is not manned by operation personnel or when the thermal oxidizer is not being operated, opacity monitoring as specified in *Appendix B* of this permit shall be utilized for the thermal oxidizer.	Rule 335-3-4-.01(1)(a)& (b)
Recordkeeping and Reporting Requirements	
1. A record of the information specified in provisos 1(a) through (i) of this section of this subpart shall be maintained and made available for inspection.	Rule 335-3-16-.05(c)(2)
(a) The date, starting time and duration of each deviation from the requirements specified in this subpart along with the cause and corrective actions taken	

Provisos for SRU and Thermal Oxidizer

Federally Enforceable Provisos	Regulations
(b) The date, time and results of each performance tests along with any other tests conducted on the thermal oxidizer that provides additional stack pollutant content data	
(c) The date and time of each shut down and start up of either the gas sweetening unit or the 3 stage Claus sulfur recovery unit or the thermal oxidizer	
(d) Date and type of maintenance that affects air emissions	
(e) Results of the daily visual inspections of the thermal oxidizer	
(f) Results of each visible emission observation when required	
(g) The three hour rolling average CMS calculations and analysis of the sulfur recovery and/or the sulfur dioxide emissions	
(h) The three hour rolling average of the thermal oxidizer firebox temperature	
(i) The information required by the recordkeeping section of Subparts A and §60.647 of 40 CFR Part 60	§60.7 §60.647
2. Monitoring reports meeting the requirements specified in proviso 2(a) through (c) of this section of this subpart shall be submitted to the Department.	Rule 335-3-16-.05(c)(2) Rule 335-3-16-.05(c)(3)(i)
(a) Each report shall identify each incidence of deviation from a permit term or condition including those that occur during startups, shutdowns, and malfunctions.	
(1) A deviation shall mean any condition determined by observation, by data derived from any monitoring or testing or recordkeeping which is required by the permit that can be used to determine or indicate compliance, that identifies an affected source has failed to meet an applicable emission limit or standard or that a work practice was not complied with or completed.	
(2) If no deviation event occurred during the reporting period, a statement that indicates there were no deviations from the permit requirements shall be included in the report.	

Provisos for SRU and Thermal Oxidizer

Federally Enforceable Provisos	Regulations

(b) An Excessive Emission and CMS Performance Report and Summary Report meeting the requirements specified in provisos 2(b)(1) through (3) to this section of this subpart shall be submitted to the Department.

(1) A deviation shall consist of, but is not limited to, any period of time during which the following occurs:

(i) There was a failure to maintain the three hour rolling average sulfur recovery efficiency or sulfur dioxide emission rate and the daily 24 hour average sulfur dioxide emission rate at a value that is equal to or greater than the sulfur recovery efficiency or equal to or less than the sulfur dioxide emission rate that is required in the *emissions standards* section of this subpart.

(ii) There was a failure to maintain the hourly average thermal oxidizer firebox at temperature greater than 1300 ^{o}F.

(iii) There was a failure of the continuous emission monitoring system to meet the requirements specified in Appendix F 40 CFR Part 60 while the sulfur recovery unit or the thermal oxidizer remained in operation.

(2) Each report shall cover a calendar quarter period and shall be submitted using the following reporting schedule:

Reporting Period	**Submittal Date**
January 1st through March 31st	April 30th
April 1st through June 30th	July 31st
July 1st through September 30th	October 31st
October 1st through December 31st	January 31st

(3) Except as provided for in proviso 2(d) of this section, each report shall meet the requirements specified in either §60.7(c) of 40 CFR Part 60, Subpart A.

(c) A Periodic Monitoring Report (PMR) meeting the requirements specified in provisos 2(c)(1) through (3) of this section of this subpart shall be submitted to the Department.

(1) A deviation shall consist of, but is not limited to, any period of time during which the following occurs:

Federally Enforceable Provisos	Regulations
(i) There was a failure to meet the daily, quarterly and annual requirements specified in Appendix F of 40 CFR Part 60.	
(ii) There was a failure to maintain the 6-minute average opacity at a value less than or equal to 20% for no more than one 6-minute period when utilizing Method 9.	
(iii) There was a failure to maintain the 6-minute averaging opacity at a value less than or equal to 40% during any 6-minute period when utilizing Method 9.	
(iv) There was a failure to maintain the accumulated minutes in which visible emissions were observed at a value less than or equal to 12 minutes when utilizing Method 22.	
(v) There was a failure to meet the requirements specified in the c*ompliance and performance test methods and procedures* section of this subpart.	
(vi) There was a failure to meet the requirements specified in the *emission monitoring* section of this subpart.	
(vii) There was a failure to meet the requirements specified in the *recordkeeping and reporting requirements* section of this subpart.	
(viii) There was a failure to take immediate corrective actions when a deviation occurred.	
(2) Except as provided for in proviso 2(d) of this section, the report shall meet the requirements specified in proviso 2(c)(2)(i).	
(i) For each deviation event, the following information shall be submitted.	
(I) *Emission source description*	
(II) *Permit requirement*	
(III) *Date*	

Provisos for SRU and Thermal Oxidizer

Federally Enforceable Provisos	Regulations
(IV) *Starting time*	
(V) *Duration*	
(VI) *Actual quantity of pollutant or parameter*	
(VII) *Cause*	
(VIII) *Actions taken to return to normal operating conditions*	
(IX) *Total operating hours of the affected source during the reporting period*	
(X) *Total hours of deviation events during the reporting period*	
(XI) *Total hours of deviation events that occurred during start ups, shut downs, and malfunctions during the reporting period*	
(3) Each report shall cover a calendar semi-annual period and shall be submitted using the following reporting schedule:	
(d) The report content and format in proviso 2(b) and (c) of this section may be modified upon receipt of Departmental approval.	
3. Each deviation from the requirements specified in this subpart, including those that occur during startups, shutdowns, and malfunctions, shall be reported to the Department in a manner that complies with proviso 15(b) and 21(b) of the *general proviso* subpart of this permit.	Rule 335-3-16-.05(c)(2) Rule 335-3-16-.05(c)(3)(ii)

Reporting Period	**Submittal Date**
January 1st through June 30th	July 31st
July 1st through December 31st	January 31st

Summary Page for Facility Flares

Permitted Operating Schedule: **24** Hours/Day x **365** Days/Year = **8760** Hours/Year

Emission Limitations:

Emission Point	Description	Pollutant	Emission Limit	Regulations
Individual Sources:				
FL02 Main Process Flare (*NSPS KKK & NESHAP HH Flare)*		Opacity	No Visible Emissions	§60.18(c)(1) §63.11(b)(4)
		H_2S	Burn gas with 0.10 grains of H_2S/scf	Rule 335-3-5-.03(1)
		H_2S	20 ppbv offsite	Rule 335-3-5-.03(2)
FL03 Compressor Seal Process Flare *(NSPS KKK Flare)*		Opacity	No Visible Emissions	§ 60.18(c)(1)
		H_2S	Burn gas with 0.10 grains of H_2S/scf	Rule 335-3-5-.03(1)
		H_2S	20 ppbv offsite	Rule 335-3-5-.03(2)
FL04 Produced & Process Water System Emergency Flare		Opacity	No more than one 6 min avg. > 20% AND No 6 min avg. > 40%	Rule 335-3-4-.01(1)(a) Rule 335-3-4-.01(1)(b)
		H_2S	Burn gas with 0.10 grains of H_2S/scf of gas	Rule 335-3-5-.03(1)
		H_2S	20 ppbv offsite	Rule 335-3-5-.03(2)
FL05 Condensate Loading/Tank Process Flare (*NSPS K_b and NSPS KKK Flare*)		Opacity	No Visible Emissions	§60.18(c)(1)
		H_2S	Burn gas with 0.10 grains of H_2S/scf of gas	Rule 335-3-5-.03(1)
		H_2S	20 ppbv offsite	Rule 335-3-5-.03(2)

Emission Limitations (Con't):

Emission Point	Description	Pollutant	Emission Limit	Regulations
Facility-wide Emission Limits:				
	Available Sulfur for Category II Counties	SO_2	Depends on available sulfur	Rule 335-3-5-.03(3)
	• Available sulfur ≤ 10 LTons/Day Or	SO_2	Unlimited	
	• Available sulfur > 10 LTons/Day & ≤ 50 LTons/Day Or	SO_2	560 Lbs SO_2/Hour	
	• Available sulfur > 50 LTons/Day & ≤ 100 LTons/Day Or	SO_2	0.10 Lbs SO_2/Lb S. processed	
	• Available sulfur > 100 LTons/Day	SO_2	0.08 Lbs SO_2/ Lb S. processed	
	Allowable SO_2 emission increase relative to the H_2S content of acid gas:	SO_2	Depends on the mole percent of H_2S in Dry Acid Gas	Rule 335-3-5-.03(3)(a)
	• H_2S% in acid gas > 50% & ≤ 60% Or	SO_2	0.02 Lbs SO_2/ Lb S. processed	
	• H_2S% in acid gas > 40% & ≤ 50% Or	SO_2	0.04 Lbs SO_2/ Lb S. processed	
	• H_2S% in acid gas > 30% & ≤ 40% Or	SO_2	0.06 Lbs SO_2/ Lb S. processed	
	• H_2S% in acid gas > 20% & ≤ 30%	SO_2	0.10 Lbs SO_2/ Lb S. processed	
	• Less than 20%	SO_2	Use best available control technology	
		H_2S	Burn gas with > 0.10 grains of H_2S/scf of gas	Rule 335-3-5-.03(1)
		H_2S	20 ppbv offsite	Rule 335-3-5-.03(2)
Natural Gas Processing Facilities in Escambia County with the capacity of greater than 50 MMscf per day of sour gas.		Total Sulfur Compounds (TSC)	Depends on available sulfur	Rule 335-3-5-.03(4)(a)
	Available Sulfur • Up to 575 Ltons/Day	TSC	0.140 Lbs of Total Sulfur Compounds/ Lb of Available Sulfur	
	• 575 to 1,031 Ltons/Day	TSC	$0.186-8.57 \times 10^{-7}$ S S= lb/hr of available sulfur	
	• Over 1,031 Ltons/day	TSC	10,008 lb/hr	

Provisos for Facility Flares

Federally Enforceable Provisos	Regulations
Applicability	
1. Flare No. FL04 shall be subject to the requirements of ADEM Admin. Code R. 335-3-4-.01, "*Visible Emissions*" and the requirements specified in this subpart of this permit.	Rule 335-3-4-.01(1)
2. The BEC Plant shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-5-.03(1), "*Petroleum Production*" and the requirements specified in this subpart of this permit. The sulfur recovery unit/thermal oxidizer and facility flares would be used to comply with this regulation.	Rule 335-3-5-.03(1)
3. The BEC Plant shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-5-.03(4) and the requirements specified in this subpart of this permit.	Rule 335-3-5-.03(4)
4. All facility flares shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-16, "*Major Source Operating Permits*" and the requirements specified in this subpart of this permit.	Rule 335-3-16-.03
5. Flare No. FL02 shall be subject to the requirements specified in §60.18 of 40 CFR Part 60, the requirements specified in §63.11 of 40 CFR Part 63, and as specified in this subpart of this permit.	§60.633(g) & §60.18 §63.771(d)(1)(iii) & §63.11(b)
6. Flare No. FL03 shall be subject to the requirements specified in §60.18 of 40 CFR Part 60 and in this subpart of this permit.	§60.482-10(d) & §60.18
7. Flare No. FL05 shall be subject to the requirements specified in §60.18 of 40 CFR Part 60 and in this subpart of this permit.	§60.112b(a)(3)(ii)) §60.633(g), & §60.18
8. Flare No. FL02 flare shall be subject to the requirements specified in 40 CFR Part 64, "*Compliance Assurance Monitoring*" as indicated in proviso 33 of the *General Permit Provisos* subpart and in this subpart of this permit.	40 CFR Part §64
Emissions Standards	
1. Flare No. FL04 shall meet the following opacity standards:	Rule 335-3-4-.01(1)
(a) Except for one 6-minute period during any 60-minute period, this flare shall not discharge into the atmosphere particulate that results in an opacity greater than 20%, as determined by a 6-minute average.	Rule 335-3-4-.01(1)(a)
(b) At no time shall this flare discharge into the atmosphere particulate that results in an opacity greater than 40%, as determined by a 6-minute average.	Rule 335-3-4-.01(1)(b)

Provisos for Facility Flares

Federally Enforceable Provisos	Regulations
2. Except as is provided for in proviso 2(a) of this section of this subpart, each process gas stream containing more than 0.10 of a grain of hydrogen sulfide per Scf shall not be emitted into the atmosphere unless it is properly burned to maintain the ground level concentrations of hydrogen sulfide to less than twenty (20) parts per billion beyond plant property limits, averaged over a thirty (30) minute period.	Rule 335-3-5-.03(2)
(a) Provided vessels or equipment are being de-pressured and/or emptied and the reduced pressure will not allow flow of the process gas stream to the combustion device, the venting to the atmosphere of any gas stream shall be allowed, but the duration of the venting shall not exceed 15 continuous minutes.	
3. Sulfur dioxide (SO_2) emissions from the BEC Plant, which depend on the amount of available sulfur processed, shall not exceed the following allowables:	Rule 335-3-5-.03(3)

Available Sulfur (Long Tons/Day)	Permitted Emissions of SO_2
Up to 10	No Limit
10 to 50	560 lbs/hour
50 to 100	0.10 lbs. SO_2/lb. S processed
Over 100	0.08 lbs. SO_2/lb. S processed

Federally Enforceable Provisos	Regulations
4. The allowable emissions of sulfur dioxide, specified in proviso 3 of this section of this subpart, are increased as follows to allow for dry acid gas streams containing less than 60 percent hydrogen sulfide (H_2S):	Rule 335-3-5-.03(3)(a)

Mole Percent of Hydrogen Sulfide In Dry Acid Gas (mol % H_2S)	Additional SO_2 Emissions Allowed
50% but less than 60%	0.02 lbs. SO_2/lb. S processed
40% but less than 50%	0.04 lbs. SO_2/lb. S processed
30% but less than 40%	0.06 lbs. SO_2/lb. S processed
20% but less than 30%	0.10 lbs. SO_2/lb. S processed
Less than 20%	Must utilize the best available control technology, with consideration to the technical practicability and economic reasonableness of reducing or eliminating the emissions from the facility.

Provisos for Facility Flares

Federally Enforceable Provisos	Regulations
5. Total sulfur compound (TSC) emissions from the BEC Plant, measured as sulfur dioxide, shall not exceed the following allowables depending on the amount of available sulfur:	Rule 335-3-5-.03(4)(a)

Available Sulfur (Long Tons/Day)	Permitted Emissions of Total Sulfur Compounds
Up to 575	0.140 pounds of total sulfur compounds per pound of available sulfur
575 to 1031	Pounds of total sulfur compounds per pound of available sulfur = $0.186 - 8.57 \times 10^{-7}\mathbf{S}$ where **S** = lb/hr of available sulfur
Over 1031	10,008 lb/hr

Federally Enforceable Provisos	Regulations
6. If flare Nos. FL02, FL03, and FL05 are used as a control device to comply with an NSPS or NESHAP, they shall meet the following requirements:	§60.112b(a)(3)(ii), §60.633(g) §60.482-10(d), & §63.771(d)(1)(iii)
(a) Shall be designed for and operated with no visible emissions, except for a 5-minute period during any consecutive 2-hour period	§60.18 (c)(1) & §63.11(b)(4)
(1) Method 22 of Subpart 60 Appendix A shall be used to determine compliance with this requirement	§60.18 (f)(1), §63.11(b)(4), §60.113b(d), §63.772(e)(2)(i), & §60.485(g)(1)
(2) The observation period is 2 hours and shall be used according to Method 22	
(b) Shall be operated with a flame present at all times	§60.18 (c)(2) & §63.11(b)(5)
(1) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.	§60.18 (f)(2), §63.11(b)(5), §60.485(g)(2) & §60.113b(d)
(c) Shall be steam-assisted, air-assisted, or non-assisted	§60.18(c)(6)& §63.11(b)(2)
(d) Shall adhere to the requirements specified in either proviso 6(d)(1) and 6(d)(2) of this section of this subpart or the requirements specified in proviso 6(d)(3) of this section of this subpart.	§60.18 (c)(3) & §63.11(b)(6)

Provisos for Facility Flares

Federally Enforceable Provisos	Regulations
(1) Adhere to either the heat content specifications found in §63.11(b)(6)(ii) or §60.18 (c)(3)(ii)	
(i) The net heating value of gas being combusted in a flare would be determined as specified in 40 CFR §60.18 (f)(3), 40 CFR §63.11(b)(6)(ii), and 40 CFR §60.485(g)(4)	
(2) Adhere to the maximum tip velocity specifications found in §63.11(b)(7) or (b)(8) or §60.18 (c)(4)	
(i) The actual exit velocity of the flare would be determined as specified in 40 CFR §60.18(f)(4), 40 CFR §63.11(b)(7)(i), and 40 CFR §60.485(g)(1)	
(ii) The maximum permitted velocity for steam-assisted and nonassisted flares would be determined as specified in 40 CFR §60.18 (f)(5) and 40 CFR §63.11(b)(7)(iii)	
(iii) The maximum permitted velocity for air assisted flares would be determined as specified in 40 CFR §60.18 (f)(6), 40 CFR §63.11(b)(8), and 40 CFR §60.485(g)(3)	
(3) Adhere the requirements specified in §63.11(b)(6)(i) or §60.18 (c)(3)(i)	
(e) Shall be monitored to ensure that they are operated and maintained in conformance with their designs	§60.18(d), §63.11(b)(1), & §60.486(d)(3)
(f) Shall be operated at all times when emissions may be vented to them	§60.18 (e), §63.11(b)(3), §63.771(d)(4), §60.482-10(m) & §60.113b(d)
Compliance and Performance Test Methods and Procedures	
1. Except when a process gas stream can not be sent to the flares, a daily visible emissions observation shall be performed. EPA Test Method 9 or Method 22 shall be utilized for flare No. FL04 and EPA Test Method 22 shall utilized for flares Nos. FL02, FL03, and FL05 to demonstrate compliance with the opacity standards.	Rule 335-3-4-.01(2) §60.18 (f)(1), §63.11(b)(4)

Provisos for Facility Flares

Federally Enforceable Provisos	Regulations
2. Each process gas stream that can be sent to the facility flares shall be tested for its heat content and hydrogen sulfide content in accordance to the requirements specified in proviso 2(a) through (e) of this section of this subpart.	Rule 335-3-16-.05(c)(1)(i)
(a) Heat content and hydrogen sulfide content testing shall consist of capturing one representative sample of the stream at a frequency of no less than once each twelve (12) months.	
(b) The sample shall be analyzed for its Btu content by utilizing the ASTM Analysis Method D1826-77 or equivalent method. [Fuel Heat Content (Btu/Scf)]	
(c) The sample shall be analyzed for its hydrogen sulfide content by utilizing the Tutwiler procedures found in 40 CFR §60.648 or the chromatographic analysis procedures found in ASTM E-260 or the stain tube procedures found in GPA 2377-86 or those provided by the stain tube manufacture. [Stream H_2S (Mole %)]	
(d) Provided multiple process streams can be sent to the flare and it is possible to capture a common stream whose contents would be representative of all the streams, that common stream may be used instead of the individual process streams.	
(e) The frequency of this testing may be modified upon receipt of Department approval.	
Emission Monitoring	
1. Monitoring for the facility flares shall be met as specified in *Appendix C* of this permit.	§64.6(b) & (c) Rule 335-3-16-.05(c)(1)
2. Periodic Monitoring for Flare Nos. FL03, FL04, and FL05 shall be met as specified in Appendix C of this permit.	Rule 335-3-16-.05(c)(1)
3. Opacity Monitoring for the Facility Flares shall be met as specified in *Appendix D* of this permit.	Rule 335-3-4-.01(1)(a) & (b)
Record Keeping and Reporting Requirements	
1. A record of the information specified in provisos 1(a) through (l) of this section of this subpart shall be maintained and made available for inspection.	Rule 335-3-16-.05(c)(2)

Provisos for Facility Flares

Federally Enforceable Provisos	**Regulations**

(a) The date, starting time and duration of each deviation from the requirements specified in this subpart along with the cause and corrective actions taken.

(b) Results of the daily visual emission observations conducted on each facility flare

(c) Stream H_2S Content

[Stream H_2S (Mole %)]

(d) Name of stream that was flared

(e) Stream volume that was sent to each facility flare

[Stream Volume Burned (MScf/Day)]

(f) Assist gas volume that was sent to Flare No. FL02

[Assist Gas Volume Burned (MScf/Day)]

(g) Stream H_2S (Lbs/Day) =

[Stream Volume Burned (MScf/Day)] X [1000 Scf/MScf)] X
[1 Mole/380 SCF] X [{Stream H_2S (Mole %)}/{100}] X
[34 Lbs. H_2S/Mole H_2S]

(h) Flare H_2S Feed Rate (Lbs/Day) =

$\sum$ of Stream H_2S (Lbs/Day)

(i) Flare SO_2 (Lbs/Day) =

$$\frac{[\text{ Flare } H_2S \text{ Feed Rate (Lbs/Day) }] \text{ X } [\text{ 64 Lbs of } SO_2/\text{ Lb Mole }] \text{ X } [\text{ 0.98 }]}{[\text{ 34 Lbs } H_2S/\text{Lb Mole }]}$$

Assuming a 98% destruction efficiency

(j) Number of hours each flare operated during the day =

[Flare Hours (Hours/Day)]

(k) H_2S feed (Lbs/Hour) =

$$\frac{\text{Flare } H_2S \text{ Feed Rate (Lbs/Day)}}{\text{Flare Hours (Hours/Day)}}$$

(l) Available sulfur (LTons/Day) =

H_2S Feedrate (Lbs H_2S/Hour) X (24 Hours/Day) X
(1 LTons/2240 Lbs) X (32 Lbs S/34 Lbs H_2S)

Provisos for Facility Flares

Federally Enforceable Provisos	Regulations
2. Monitoring reports meeting the requirements specified in proviso 2(a) through (c) of this section of this subpart shall be submitted to the Department.	Rule 335-3-16-.05(c)(2) Rule 335-3-16-.05(c)(3)(i)

(a) Each report shall identify each incidence of deviation from a permit term or condition including those that occur during startups, shutdowns, and malfunctions.

(1) A deviation shall mean any condition determined by observation, by data derived from any monitoring or testing or recordkeeping which is required by the permit that can be used to determine or indicate compliance, that identifies an affected source has failed to meet an applicable emission limit or standard or that a work practice was not complied with or completed.

(2) If no deviation event occurred during the reporting period, a statement that indicates there were no deviations from the permit requirements shall be included in the report.

(b) An Excessive Emission and CMS Performance Report and Summary Report meeting the requirements specified in provisos 2(b)(1) through (3) to this section of this subpart shall be submitted to the Department.

(1) A deviation shall consist of, but is not limited to, any period of time during which the following occurs:

(i) There was a failure to maintain the presence of a flame or igniter spark at the flare tip of flare No. FL02 when a process gas stream could have been sent to it.

(2) Each report shall cover a calendar quarter period and shall be submitted using the following reporting schedule:

Reporting Period	**Submittal Date**
January 1st through March 31st	April 30th
April 1st through June 30th	July 31st
July 1st through September 30th	October 31st
October 1st through December 31st	January 31st

(3) Except as provided for in proviso 2(d) of this section, each report shall meet the requirements specified in §60.7(c) of 40 CFR Part 60, Subpart A.

Provisos for Facility Flares

Federally Enforceable Provisos	Regulations

(c) A Periodic Monitoring Report (PMR) meeting the requirements specified in provisos 2(c)(1) through (3) of this section of this subpart shall be submitted to the Department.

(1) A deviation shall consist of any period of time during which the following occurs:

(i) There was a failure to maintain the presence of a flame or igniter spark at the flare tip of flare Nos. FL03, FL04, and FL05 when a process gas stream could have been sent to one of them.

(ii) There was a failure for Flare Nos. FL02, FL03, and FL05 to meet the design specifications specified in §60.18 and §63.11.

(iii) There was a failure to keep the period in which a process gas steam was vented into the atmosphere to less than or equal to 15 consecutive minutes in duration for the facility flares.

(iv) There was a failure to keep the assist gas to acid gas volume ratio to equal to or greater than 1 as specified in *Appendix C* for flare No. FL02.

(v) There was a failure to keep offsite hydrogen sulfide concentrations average over a 30 minute period to less than 20 ppbv as determined by air quality modeling study.

(vi) There was a failure to maintain visible emissions to less than or equal to an accumulated total of five (5) minutes provided the observation was conducted on flare Nos. FL02, FL03, and FL05.

(vii) There was a failure to maintain the 6-minute average opacity at a value less than or equal to 20% for no more than one 6-minute period when utilizing Method 9 provided the observation was conducted on flare No. FL04.

Federally Enforceable Provisos	Regulations

(viii) There was a failure to maintain the 6-minute averaging opacity at a value less than or equal to 40% during any 6-minute period when utilizing Method 9 provided the observation was conducted on flare No. FL04.

(ix) There was a failure to meet the requirements specified in the *compliance and performance test methods and procedures* section of this subpart.

(x) There was a failure to meet the requirements specified in the *emission monitoring* section of this subpart.

(xi) There was a failure to meet the requirements specified in the *recordkeeping and reporting requirements* section of this subpart.

(xii) There was a failure to take immediate corrective actions when a deviation occurred.

(2) Except as provided for in proviso 2(d) of this section, the report shall meet the requirements specified in proviso 2(c)(2)(i).

(i) For each deviation event, the following information shall be submitted.

(I) *Emission source description*

(II) *Permit requirement*

(III) *Date*

(IV) *Starting time*

(V) *Duration*

(VI) *Actual quantity of pollutant or parameter*

(VII) *Cause*

(VIII) *Actions taken to return to normal operating conditions*

Provisos for Facility Flares

Federally Enforceable Provisos	Regulations
(IX) *Total operating hours of the affected source during the reporting period*	
(X) *Total hours of deviation events during the reporting period*	
(XI) *Total hours of deviation events that occurred during start ups, shut downs, and malfunctions during the reporting period*	
(3) Each report shall cover a calendar semi-annual period and shall be submitted using the following reporting schedule:	
(d) The report content and format in proviso 2(b) and (c) of this section may be modified upon receipt of Departmental approval.	
3. Each deviation from the requirements specified in this subpart, including those that occur during startups, shutdowns, and malfunctions, shall be reported to the Department in a manner that complies with proviso 15(b) and 21(b) of the general proviso subpart of this permit.	Rule 335-3-16-.05(c)(2) Rule 335-3-16-.05(c)(3)(ii)

Reporting schedule for (3):

Reporting Period	**Submittal Date**
January 1^{st} through June 30^{th}	July 31^{st}
July 1^{st} through December 31^{st}	January 31^{st}

Summary Page for Storage Vessels I

Permitted Operating Schedule: **24** Hours/Day x **365** Days/Year = **8760** Hours/Year

Emission Limitations:

Emission Point	Description	Pollutant	Emission Limit	Regulations
Individual Sources:				
Storage Vessels I:				
(T101A)-	211,506 Gallon Condensate Vertical Fixed Roof Storage Tanks	VOC		§60.110(a) 40 CFR 60, Subpart K
(T101B)-	211,506 Gallon Condensate Vertical Fixed Roof Storage Tanks	VOC		§60.110(a) 40 CFR 60, Subpart K
(T101C)-	211,506 Gallon Condensate Vertical Fixed Roof Storage Tanks	VOC		§60.110(a) 40 CFR 60, Subpart K

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Provisos for Storage Vessels I

Federally Enforceable Provisos	Regulations
Applicability	
1. The T101A, T101B, and T101C (Storage Vessels I) shall be subject to the requirements of 40 CFR 60 Subpart K, *"Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced after June 11, 1973 and Prior to May 19, 1978"* and the requirements specified in this subpart of this permit.	§60.110(a) §60.110(c)(2)
2. Storage Vessels I shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-16, "*Major Source Operating Permits*" and the requirements specified in this subpart of this permit.	Rule 335-3-16-.03
Emissions Standards	
1. Storage Vessels I shall store a petroleum liquid with a true vapor pressure greater than or equal to 1.5 psia but less than 11.1 psia and shall meet the VOC emissions standards by equipping each storage vessels with one of the following control devices: (a) Floating roof (b) Vapor recovery system (c) An equivalent of either proviso 1(a) or 1(b) of this section of this subpart.	§60.112(a)(1)
Compliance and Performance Test Methods and Procedures	
1. There are no testing requirements to demonstrate compliance with this subpart.	
Emission Monitoring	
1. Except that Storage Vessels I are equipped with a vapor recovery and return or a disposal system in accordance with the requirements of §60.112(a)(1), monitoring shall be in the form of maintaining records specified in the *recordkeeping and reporting* section of this subpart of this permit.	§60.112(a)(1) §60.112(d)(2)
Record Keeping and Reporting Requirements	
1. The following records shall be maintained to demonstrate compliance with the monitoring requirements of this subpart: (a) Record of the petroleum liquid stored	§60.113(a)

Provisos for Storage Vessels I

Federally Enforceable Provisos	Regulations
(b) Period of storage (c) Maximum true vapor pressure of the liquid during the respective storage period	

Summary Page for Storage Vessels II

Permitted Operating Schedule: **24** Hours/Day x **365** Days/Year = **8760** Hours/Year

Emission Limitations:

Emission Point	Description	Pollutant	Emission Limit	Regulations
Individual Sources:				
Storage Vessels II:				
(T101D)- 420,000 Gallon Condensate Vertical Fixed Roof Storage Tanks		VOC		§60.110b(a) 40 CFR 60, Subpart K_b

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Provisos for Storage Vessels II

Federally Enforceable Provisos	Regulations
Applicability	
1. The T101D storage vessel (Storage Vessels II) shall be subject to the requirements of 40 CFR 60 Subpart K_b, *"Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced after June 23, 1984"*, and the requirements specified in this subpart of this permit.	§60.110b(a)
2. Storage Vessels II shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-16, "*Major Source Operating Permits*" and the requirements specified in this subpart of this permit.	Rule 335-3-16-.03
Emissions Standards	
1. The T101D storage vessel shall store a volatile organic liquid with a maximum true vapor pressure greater than or equal to 76 kilopascals (kPa) (or 11.1 psia) and shall meet the VOC emissions standards by meeting the requirements specified in proviso 1(a) or (b) of this section of this subpart.	§60.112b(b)
(a) A closed vent system (CVS) and control device as specified in §60.112b(a)(3) and as follows:	§60.112b(b)(1)
(1) The closed vent system must meet the following requirements:	§60.112b(a)(3)(i)
(i) Be designed to collect all volatile organic compounds (VOC) vapors and gases discharged from the storage vessel	
(ii) Be operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV §60.485(b)	
(2) The control device must meet the following requirements:	§60.112b(a)(3)(ii)
(i) Be designed and operated to reduce inlet VOC emissions by 95 percent or greater	
(ii) If a flare is used, it shall meet the specifications described in §60.18(e) and (f)	§60.113b(d)

Provisos for Storage Vessels II

Federally Enforceable Provisos	Regulations
(b) System equivalent to a closed vent system and control device as specified as provided in §60.114b	§60.112b(b)(2)
Compliance and Performance Test Methods and Procedures	
1. EPA Test Method 21 shall be used to determine no detectable emissions from the closed vent system as specified in §60.485(c) of 60 Subpart VV.	§60.112b(a)(3)(i)
2. EPA Method 22 shall be used to determine visible emissions from the flare used to control emissions from this storage tank as specified in §60.113b(d). The observation period is 2 hours and shall be used according to Method 22.	§60.18(f) §60.113b(d)
Emission Monitoring	
1. A storage tank equipped with a closed vent system and a control device shall be exempt from the monitoring requirements specified in §60.116 (c) and (d).	§60.116b(g)
Record Keeping and Reporting Requirements	
1. The following record requirements shall be met to demonstrate compliance with this subpart:	
(a) Records showing the dimensions of the storage vessel and an analysis showing the capacity of storage vessels shall be kept readily accessible for the life of the source	§60.116b(a) & (b)
(b) Records of all periods of operation during which the flare pilot flare was absent	§60.115b(d)(2)
(c) Daily visible emission observations of the flare	
(d) All other records, except those specified in proviso 1(a) of this section of this subpart, shall be maintained for a period of at least two years.	§60.116b(a)
2. The following reporting requirements shall be met if a closed vent system and a flare is used to comply with the VOC emission standards:	§60.112b

Provisos for Storage Vessels II

Federally Enforceable Provisos	Regulations
(a) A report containing the measurements required by §60.18(f)(1) through (6) shall be submitted to the Department within 6 months of the initial start-up date	§60.8 §60.115b(d)(1)
(b) Report of all periods in which the pilot flame was absent from the flare tip	§60.115b(d)(3)
(1) Each report shall cover a calendar semi-annual period and shall be submitted to the Department using the following reporting schedule:	

Reporting Period	**Submittal Date**
January 1^{st} through June 30^{th}	July 31^{st}
July 1^{st} through December 31^{st}	January 31^{st}

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Summary Page for Equipment Leaks of Volatile Organic Compounds & Hazardous Air Pollutants

Permitted Operating Schedule: **24** Hours/Day x **365** Days/Year = **8760** Hours/Year

Emission limitations:

Emission Point #	Description	Pollutant	Emission Limit	Regulation
	Affected sources under this subpart	Fugitive VOC	LDAR work practices	40 CFR §60 Subpart KKK
	Ancillary equipment in VHAP service located at an oil and gas production facility	Fugitive HAPs	LDAR work practices	40 CFR §63 Subpart HH

Affected sources within process unit:

- Compressors, except reciprocating compressors, in VOC service or wet gas service located at an onshore natural gas processing plant
- Group of all equipment within a process unit located at a natural gas processing plant that is in VOC or wet gas service:
  - Each valve
  - Each pump
  - Each pressure relief device
  - Each sampling connection system
  - Each open-ended valve or line
  - Each flange or other connector
- Each glycol dehydration unit
- Each sweetening unit
- Liquefied natural gas unit

Process units at the BEC Plant:

Inlet Gathering & Separation Unit
Condensate Stabilization Unit
Gas Sweetening Unit
De-Methanizing Unit
De-Propanizing Unit
De-Butanizing Unit
Sulfur Recovery Unit
Produced & Process Water System
Closed vent system with flare
Condensate Loading Rack

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Provisos for Equipment Leaks of VOC & HAPS

Federally Enforceable Provisos	Regulations
Applicability	Rule 335-3-10-.02(63)
1. All affected facilities shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-16, "*Major Source Operating Permits*" and the requirements specified in this subpart of this permit.	Rule 335-3-16-.03
2.	
3. Except as specified in 40 CFR §60.630(d), affected facilities at onshore natural gas processing plants that commences construction, reconstruction, or modification after January 20, 1984 are subject to the requirements found in 40 CFR 60, Subpart KKK "*Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants*". Affected facilities under this subpart are as follows:	§60.630(a)(1) §60.630(b)
(a) Each compressor in VOC service or in wet gas service, except reciprocating compressors in wet gas service	§60. 630(a)(2) §60. 633(f)
(b) The group of all equipment within a process unit in VOC service or in wet gas service as specified in proviso 1(b)(1) through (5).	§60. 630(a)(3)
(1) Each pump	
(2) Each pressure relief device	
(3) Each open-ended valve or line	
(4) Each valve	
(5) Each flange or other connector	
(c) A compressor station, dehydration unit, sweetening unit, underground storage tanks, field gas gathering system, or liquefied natural gas units located at the BEC Plant would also be covered under 40 CFR 60, Subpart KKK.	§60. 630(e)
Emissions Standards	Rule 335-10-.02(63)
1. The emission standards as specified in either 1(a) or 1(b) shall be met to demonstrate compliance with this subpart.	§60.632(a) §60.482-1(a) §60.480(e)
(a) Except as specified in §60.633 of 40 CFR 60 Subpart KKK, each affected facility shall comply with the emission standards specified in the following provisos:	

Provisos for Equipment Leaks of VOC & HAPS

Federally Enforceable Provisos	Regulations
(1) Pumps in light liquid service shall comply with §60.482-2 of 40 CFR 60, Subpart VV, except as specified in §60.633(d) and (e) of 40 CFR 60, Subpart KKK.	§60.482-1(a) §60.482-2 §60.633(d) & (e)
(2) Compressors shall comply with §60.482-3 of 40 CFR 60, Subpart VV, except as specified in §60.633(f) of 40 CFR 60, Subpart KKK.	§60.482-1(a) §60.482-3 §60.633(f)
(3) Pressure relief devices in gas/vapor service shall comply with §60.482-4 of 40 CFR 60, Subpart VV, except as specified in §60.633 (b), (d), and (e) of 40 CFR 60, Subpart KKK.	§60.482-1(a) §60.482-4 §60.633(b), (d), & (e)
(4) Sampling connection systems under 40 CFR 60, Subpart KKK are exempt from the requirements of §60.482-5 of 40 CFR 60, Subpart VV.	§60.633(c)
(5) Open-ended valves or lines shall comply with §60.482-6 of 40 CFR 60, Subpart VV.	§60.482-1(a) §60.482-6
(6) Valves in gas/vapor service and in light liquid service shall comply with 60.482-7 of 40 CFR 60, Subpart VV, except as specified in §60.633(d) and (e) of 40 CFR 60, Subpart KKK.	§60.482-1(a) §60.482-7 §60.633(d) & (e)
(7) Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors shall comply with §60.482-8 of 40 CFR 60, Subpart VV.	§60.482-1(a) §60.482-8
(8) Delay of repair shall comply with §60.482-9 of 40 CFR 60, Subpart VV.	§60.482-1(a) §60.482-9
(9) Closed vent systems and control devices shall comply with §60.482-10 of 40 CFR 60, Subpart VV.	§60.482-1(a) §60.482-10
(i) Provided a flare is utilized to meet any of the above requirements, the flare shall comply with the requirements specified in §60.18 of 40 CFR Part 60, Subpart A.	§60.633(g)

Provisos for Equipment Leaks of VOC & HAPS

Federally Enforceable Provisos	Regulations
(b) As an alternative means of compliance, the provisions of 40 CFR 65, Subpart F may be complied with to satisfy the requirement of §60.482 through §60.487 of Subpart VV for an affected facility.	§60.480(e) §60.482-1(a)
2. Equipment that is in vacuum service is excluded from the requirements of §60.482-2 through §60.482-10 of 40 CFR 60, Subpart VV if it meets the requirements of §60.486(e)(5) of 40 CFR 60, Subpart VV.	§60.632(a) §60.482-1(d) §60.486(e)(5)
3. An owner or operator may elect to comply with the alternative standards for valves specified in §60.483-1 or 60.483-2 of 40 CFR 60, Subpart VV.	§60.632(b)
4. An owner or operator may apply for permission to use an alternative means of emission limitations as specified in §60.634 of 40 CFR 60, Subpart KKK to satisfy the requirements of §60.482 through §60.487 of 40 CFR 60, Subpart VV for an affected facility.	§60.632(c) §60.634
Compliance and Performance Test Methods and Procedures	Rule 335-3-10-.02(63)
1. Compliance with §60.482-1 to §60.482-10 of 40 CFR Part 60, Subpart VV shall be determined by the review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485 of 40 CFR 60, Subpart VV.	§60.632(d) §60.482-1(b) §60.485
Emission Monitoring	Rule 335-3-10-.02(63)
1. The inspection and monitoring requirements specified in §60.482-1 through §60.482-10 of 40 CFR Part 60, Subpart VV and either §60.483-1 or §60.483-2 of 40 CFR Part 60, Subpart VV shall be complied with.	§60.632(a) & (b)
Record keeping and Reporting Requirements	Rule 335-3-10-.02(63)
1. Recordkeeping and reporting requirements specified in §60.7 and §60.19 of 40 CFR Part 60, Subpart A and §60.486 and §60.487 of 40 CFR Part 60, Subpart VV shall be maintained, except as provided for in §60.633, §60.635 and §60.636 of 40 CFR Part 60, Subpart KKK.	§60.7 §60.19 §60.632(e) §60.486 §60.487
2. A Leak Detection and Repair (LDAR) summary report shall be submitted to the Department:	§60.636(c) §60.487(c)
(a) The report shall include the requirements specified in §60.636(c) and a summary of the recordkeeping requirements found in §60.486 as specified in §60.487(c).	

Provisos for Equipment Leaks of VOC & HAPS

Federally Enforceable Provisos	Regulations
(b) The report shall cover a calendar semi-annual period and shall be submitted to the Department on the following reporting schedule:	

Reporting Period	**Submittal Date**
January 1st through June 30th	July 31st
July 1st through December 31st	January 31st

Summary Page for Tri-ethylene Glycol (TEG) Dehydration Unit

Permitted Operating Schedule: **24** Hours/Day x **365** Days/Year = **8760** Hours/Year

Emission Limitations:

Emission Point #	Description	Pollutant	Emission Limit	Regulation
Facility Wide Sources:				
	Oil and Natural Gas Production Facilities			40 CFR 63, Subpart HH
Affected Sources at BEC Plant:				
	Tri-ethylene Glycol (TEG) Dehydration Unit	HAPs		§63.760(a) Anti-MACT Limits for Major Source
			Actual avg. flowrate of natural gas < 85 scm/day	§63.764(e)(1)(i) Area Source
			OR	
		Benzene	Actual avg. benzene emissions < 0.90 mega grams/year	§63.764(e)(1)(ii) Area Source

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Provisos for TEG Dehydration Unit

Federally Enforceable Provisos	Regulations
Applicability	
1. The TEG dehydration unit shall be subject to the requirements specified in ADEM Admin. Code R. 335-3-16, "*Major Source Operating Permits*" and the requirements specified in this subpart of this permit.	Rule 335-3-16-.03
2. The BEC Plant has limits in place to avoid being an affected source at a major source of hazardous air pollutants (HAPs) with respect to 40 CFR Part 63 Subpart HH, "*National Emissions Standards for Hazardous Air Pollutants from Oil and Natural Gas Production*". However, the facility is subject to the applicable area source requirements under this subpart. Affected area sources under this subpart shall be defined as:	§63.760(b)(2)
(a) Each tri-ethylene glycol (TEG) dehydration unit located at a facility meeting the requirements of §63.760(a).	§63.760(b)(2)
Emission Standards	
1. To demonstrate that the BEC Plant would not be a major source of HAPs emissions under subpart HH, the requirements specified in proviso 1(a) through (c) of this section of this subpart shall be met:	
(a) Install and operate one of the following controls on the gas-condensate-glycol (GCG) separator (flash tank) vent, to reduce HAP emissions by 95% or more or reduce benzene emissions to a level less than 0.90 megagrams per year as specified in §63.775(b)(1) and as follows:	§63.775(b)(1)
(1) Capture the vapors leaving the process vent with a closed vent system and send them to a control device	§63.765 (b)(1)(i))
(2) Capture the vapors leaving the process vent with a closed vent system and send them to a control device to reduce the outlet benzene emissions to a level less than 0.90 megagrams per year (1,982 lbs/yr)	§63.765 (b)(1)(ii)
(3) Control the vapors leaving the process line with a closed vent system and send them to a process line	§63.765 (c)(1)

Provisos for TEG Dehydration Unit

Federally Enforceable Provisos	Regulations
(4) Undertake a process and/or control device modification in accordance to §63.771 (e) to demonstrate that the total HAP emissions to the atmosphere from the glycol dehydration unit process vent are reduced by 95%	§63.765 (c)
(b) Route vapors from the glycol dehydration reboiler vent (GRV02) through a closed vent system that meets the requirements specified in §63.771 (c) to one of the following control devices:	§63.771 (c) §63.771 (d)(1)
(1) Condenser	§63.771(d)(1)(ii)
(2) A flare meeting the design specification of 40 CFR §63.11(b)	§63.771(d)(1)(iii))
(3) Other control devices specified in §63.771 (d)	§63.771 (d)(1)
(c) Each control device shall be operated in accordance with the requirements specified in §63.771 (d)(4)(i) and (ii)	§63.771 (d)(4)
2. The tri-ethylene glycol (TEG) dehydration unit shall comply with the standards specified in §63.764(d), except that one of the following exemptions is applicable:	§63.764(d) §63.764(e)(1)
(a) The actual annual average flowrate of natural gas to the glycol dehydration unit is less than 85 thousand standard cubic meters per day.	§63.764(e)(1)(i)
(b) The actual average emissions of benzene from the glycol dehydration unit process vent to the atmosphere are less than 0.90 mega gram per year.	§63.764(e)(1)(ii)
Compliance and Performance Test Methods and Procedures	Rule 335-3-16-.05(c)(1)(i)
1. A compliance determination shall be made using Method 22 of 40 CFR part 60, Appendix A, to determine visible emissions if a flare is used as a control device to demonstrate compliance with this subpart	§63.772(e)(2)(i)
2. To demonstrate that a condenser used to control emissions from the glycol dehydration unit process vent meets the control requirements of §63.771(d)(1), the facility may elect to conduct one of the following:	§63.772(e)
(a) A performance test using the methods and procedures specified in §63.772(e)(3)	

Provisos for TEG Dehydration Unit

Federally Enforceable Provisos	Regulations
(b) A design analysis meeting the requirements specified in §63.772(e)(4)(i)(D)	
(c) Use the alternative procedures specified in §63.772(e)(5)	
3. To demonstrate exemption from the general standards for affected sources at an area source of HAPs, the procedures found in one of the following provisos shall be complied with:	
(a) §63.772(b)(1) of 40 CFR 63 Subpart HH shall be met to determine the actual flowrate of natural gas to the glycol dehydration unit.	§63.764(e)(1)(i)
(b) 63.772(b)(2) of 40 CFR 63 Subpart HH shall be met to determine the actual average benzene emissions from the glycol dehydration unit.	§63.764(e)(1)(ii)
Emission Monitoring	
1. Monitoring for a closed vent system shall be met as specified in §63.773(c)	§63.773
2. Monitoring for a control device shall be met as specified in §63.773(d)	§63.773
Recordkeeping and Reporting Requirements	
1. The following records shall be maintained to demonstrate compliance with this subpart:	
(a) A record of each event when the benzene emissions from glycol dehydrator reboiler vent or the GCG separator are not being controlled by one the methods specified in the emission standards section.	
(b) Flare records as specified in §63.774(e)(1) through (3), if a flare is used to comply with this subpart	§63.764 (e)
(c) Determination records to demonstrate exemption from the general standards for an affected area source as specified in 40 CFR §63.774(d)(1)	§63.764 (e)(1) §63.774 (d)(1)
2. Monitoring reports that meet the requirements specified in proviso 2(a) through (c) of this section of this subpart shall be submitted to the Department.	Rule 335-3-16-.05(c)(2) Rule 335-3-16-.05(c)(3)(i)

Provisos for TEG Dehydration Unit

Federally Enforceable Provisos	Regulations

(a) Each report shall identify each incidence of deviation from a permit term or condition including those that occur during startups, shutdowns, and malfunctions.

(1) A deviation shall mean any condition determined by observation, by data derived from any monitoring or testing or recordkeeping which is required by the permit that can be used to determine or indicate compliance, that identifies an affected source has failed to meet an applicable emission limit or standard or that a work practice was not complied with or completed.

(2) If no deviation event occurred during the reporting period, a statement that indicates there were no deviations from the permit requirements shall be included in the report.

(b) A Periodic Monitoring Report (PMR) meeting the requirements specified in provisos 2(b)(1) through (3) of this section of this subpart shall be submitted to the Department.

(1) A deviation shall consist of, but is not limited to, any period of time during which the following occurs:

(i) There was a failure to control emission from the GCG separator (flash tank) vent.

(ii) There was a failure to route vapors from the glycol dehydration reboiler vent (GRV02) through a closed vent system to a control device.

(iii) There was a failure to maintain the actual annual average flowrate of natural gas to the glycol dehydration unit to less than 85 thousand standard cubic meters per day or the actual average emissions of benzene from the glycol dehydration unit process vent to the atmosphere at less than 0.90 mega gram per year.

Federally Enforceable Provisos	Regulations
(iv) There was a failure to meet the requirements of the *compliance and performance test methods and procedures* section of this subpart.	
(v) There was a failure to meet the requirements of the *recordkeeping and reporting requirements* section of this subpart.	
(vi) There was a failure to take immediate corrective actions when a deviation occurred.	
(2) Except as provided for in proviso 2(d) of this section, the report shall meet the requirements specified in proviso 2(b)(2)(i).	
(i) For each deviation event, the following information shall be submitted.	
(I) *Emission source description*	
(II) *Permit requirement*	
(III) *Date*	
(IV) *Starting time*	
(V) *Duration*	
(VI) *Actual quantity of pollutant or parameter*	
(VII) *Cause*	
(VIII) *Actions taken to return to normal operating conditions*	
(IX) *Total operating hours of the affected source during the reporting period*	
(X) *Total hours of deviation events during the reporting period*	
(XI) *Total hours of deviation events that occurred during start ups, shut downs, and malfunctions during the reporting period*	

Provisos for TEG Dehydration Unit

Federally Enforceable Provisos | **Regulations**

(c) The report shall cover a calendar semi-annual period and shall be submitted to the Department on the following reporting schedule:

Reporting Period	Submittal Date
January 1st through June 30th	July 31st
July 1st through December 31st	January 31st

(d) The report content and format in proviso 2(b) of this section may be modified upon receipt of Departmental approval.

3. Each deviation from the requirements specified in this subpart, including those that occur during startups, shutdowns, and malfunctions, shall be reported to the Department in a manner that complies with proviso 15(b) and 21(b) of the general proviso subpart of this permit.

Rule 335-3-16-.05(c)(2)
Rule 335-3-16-.05(c)(3)(ii)

APPENDIX A: MONITORING FOR SRU & THERMAL OXIDIZER

Sulfur Recovery Unit and Thermal Oxidizer Monitoring

Monitoring approach:	*Sulfur Recovery Unit Compliance Assurance Monitoring*	*Thermal Oxidizer Compliance Assurance Monitoring*
I. Indicator	**Sulfur dioxide emission rate & Total Sulfur Compound emission rate**	**Thermal Oxidizer Firebox Temperature**
A. Measurement approach	Inlet feed volume and sulfur content shall be monitored with a system capable of continuously measuring and recording the flow rate and/or the parameters utilized for flow rate calculation along with its sulfur content. Effluent volume and sulfur content shall be monitored with a system capable of continuously measuring and recording the flow rate and/or the parameters utilized for flow rate calculation along with its sulfur dioxide content. A continuous emissions monitoring system that is capable of assimilating the above information, analyzing that information and making appropriate calculations for each monitoring cycle and each rolling three hour period while recording relevant information and calculation results shall be utilized.	Firebox temperature shall be monitored with a thermocouple or equivalent device. A continuous emissions monitoring system that is capable of assimilating the above information, analyzing that information and making appropriate calculations for each monitoring cycle and each rolling three hour period while recording relevant information and calculation results shall be utilized.
II. Indicator range	**Available Sulfur** (see table below)	**Firebox temperature of shall be maintained at => 1,300 °F**

If, Available Sulfur (AS) in Long Tons/Day (LTD) Equals	**Permitted Emissions of Sulfur Dioxide (SO_2)[2]**	**Permitted Emissions of Total Sulfur Compound (TSC)**
< 10 LTD	No Limit	0.140 Lbs. of TSC/Lbs. Available Sulfur
10 LTD ≤ AS< 50 LTD	560 Lbs./Hr	0.140 Lbs. of TSC/Lbs. Available Sulfur
50 LTD ≤ AS ≤ 100 LTD	0.10 Lbs. SO_2/Lb. S processed[1]	0.140 Lbs. of TSC/Lbs. Available Sulfur
100 LTD< AS < 575 LTD	0.08 Lbs. SO_2/Lb. S processed[1]	0.140 Lbs. of TSC/Lbs. Available Sulfur
575 LTD ≤ AS ≤ 1031 LTD	0.08 Lbs. SO_2/Lb. S processed[1]	$[0.186-8.57 \times 10^{-7}\mathbf{S}]$ Lbs. of TSC/Lbs. Available Sulfur **S**=Lbs/Hr of Available Sulfur
AS >1031 LTD	0.08 Lbs. SO_2/Lb. S processed[1]	10,008 Lbs/Hr

Monitoring approach:	*Sulfur Recovery Unit Compliance Assurance Monitoring*	*Thermal Oxidizer Compliance Assurance Monitoring*

[1]Provided that the concentration of H_2S in the acid gas is less than 60% ;the SO_2 allowable emissions may be increased depending on the mol % of H_2S in the acid gas as follows:

Mole Percent of Hydrogen Sulfide (H_2S) In Dry Acid Gas (mol %)	**Additional SO_2 Emissions Allowed**
50% but less than 60%	0.02 lbs. SO_2/lb. S processed
40% but less than 50%	0.04 lbs. SO_2/lb. S processed
30% but less than 40%	0.06 lbs. SO_2/lb. S processed
20% but less than 30%	0.10 lbs. SO_2/lb. S processed
Less than 20%	Must utilize the best available control technology, with consideration to the technical practicability and economic reasonableness of reducing or eliminating the emissions from the facility.

[2] By no later than January 1, 2013, SO_2 emissions from the SRU shall not be greater than or equal to 1,818 Lbs. SO_2/hr

Monitoring approach	Sulfur Recovery Unit	Thermal Oxidizer
	A deviation is defined as anytime the three hour rolling average SO_2 rate is greater than the value calculated while utilizing the above equations or the three hour rolling average sulfur recovery efficiency is less than the value calculated while utilizing the above equations.	A deviation is defined as anytime the three hour rolling average firebox temperature is < 1,300 °F.
	A deviation triggers an immediate inspection and corrective actions that meet the requirements of 40 CFR Part 64.7(d) and reporting within 48 hours or two work days.	A deviation triggers an immediate inspection, corrective action, and reporting within 48 hours or two work days.
		The minimum firebox temperature may be modified upon receipt of Departmental approval.
A QIP threshold	If the accumulated hours of deviation events occurring exceed 5% of the sulfur recovery system operating time during any quarterly reporting period, a Quality Improvement Plan shall be developed and implemented.	If the accumulated hours of deviation events occurring exceed 5% of the sulfur recovery system operating time during any quarterly reporting period, a Quality Improvement Plan shall be developed and implemented.

Sulfur Recovery Unit and Thermal Oxidizer Monitoring

Monitoring approach:	*Sulfur Recovery Unit Compliance Assurance Monitoring*	*Thermal Oxidizer Compliance Assurance Monitoring*
	Sulfur dioxide emission rate & Total Sulfur Compound emission rate	**Thermal Oxidizer Firebox Temperature**
III. Performance criteria		
A. Data representiveness	The location of each inlet sensor shall located be upstream of the sulfur recovery unit and shall consist of a single device that monitors all streams or multiple sensors that monitors individual or multiple streams. The location of the effluent sensor shall be within the thermal oxidizer stack and shall consist of a multiple device that monitors all appropriate parameters. The volume sensor shall be accurate to within ±2.0%. The content sensor shall be accurate to within ±5.0%.	Each temperature sensor shall be located within the combustion chamber or immediately downstream of the combustion chamber. The temperature sensor shall be accurate to within ±1.0%.
B. Verification of operational status	Not applicable	Not applicable
C. QA/QC practices & criteria	A program for the continuous emission monitoring system shall be developed and implemented that meets the requirements specified in the following regulations: §60.13 of 40 CFR Part 60, Sub. A 40 CFR Part 60, App F 40 CFR Part 60, App B, PS 2 40 CFR Part 60, App B, PS 6 If a sensor fails its calibration test, the sensor shall be taken out of service until repairs and/or replacements are made and a new calibration test is undertaken and passed.	Each temperature sensor shall be calibrated at a frequency in accordance with the manufacturer's specifications, other written procedures that provide adequate assurance that the device is calibrated accurately. If the sensor fails its calibration test, the sensor shall be taken out of service until repairs and/or replacements are made and a new calibration test is undertaken and passed.
D. Monitoring frequency	Inlet volume or inlet volume parameters and inlet content shall be measured continuously. Effluent volume or effluent volume parameters and effluent content shall be measured continuously.	Temperature shall be measured continuously. Temperature shall be measured continuously.
Data collection procedure	Calculate and record hourly and rolling three hour averages of the following items: Volumes & sulfur mass rates of the Inlet streams & Thermal oxidizer effluent Actual sulfur dioxide emission rate Allowed sulfur recovery efficiency Actual sulfur recovery efficiency	Record hourly and rolling three hour average firebox temperature.

Sulfur Recovery Unit and Thermal Oxidizer Monitoring

Monitoring approach:	*Sulfur Recovery Unit Compliance Assurance Monitoring*	*Thermal Oxidizer Compliance Assurance Monitoring*
	Record each H_2S concentration analysis. Record calibration results. Record inspection results and corrective actions taken.	Record calibration results. Record inspection results and corrective actions taken.
Averaging period	Rolling three hours Daily 24 hour average	Rolling three hours

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APPENDIX B: OPACITY MONITORING FOR THERMAL OXIDIZER

Opacity Monitoring for the Thermal Oxidizer

Monitoring approach: *Periodic Monitoring*

I. Indicator — **Opacity**

A. Measurement approach

Provided that the thermal oxidizer is being operated, a daily visual inspection of the this unit for visible emissions would be required. The visual inspection shall meet the following requirements:

- Visual inspections must be conducted for a duration of at least 6 minutes during daylight hours, except as specified below.
  - A daily visual inspection is not required during periods that the production facility is unmanned by plant personnel or when a process stream can not be sent to the thermal oxidizer.
- If visible emissions, in excess of the opacity standards, are observed during the daily visual inspection of the thermal oxidizer, a visible emissions observation (VEO) shall be performed that meets the following requirements:
  - Duration of each observation shall be >= 15 minutes <u>AND</u> <= 120 minutes
  - Each observation shall be conducted in accordance to either:

    Test Method 9 of 40 CFR Part 60
    - Method 9 shall only be performed by an individual certified in using that method

    Or

    Test Method 22 of 40 CFR Part 60

II. Indicator range

2nd 6-min. opacity average <= 20%
Each 6-min. opacity average <= 40%
Or
< 12 minutes of visible emissions during observation

A deviation is defined as anytime the observed 6-minute average opacity exceeds 20% for the 2nd time when utilizing Method 9.

A deviation is defined as anytime the observed 6-minute average opacity exceeds 40% for the 1st time when utilizing Method 9.

A deviation is defined as anytime the accumulated time in which visible emissions were observed exceeds 12 minutes per observation when utilizing Method 22.

A deviation or exceedance triggers continued visible emissions observations at a frequency suitable to defining the emission deviation or exceedance event. One observation shall be undertaken to establish the end of the visible emission deviation event.

A deviation or exceedance triggers an inspection, corrective action, and immediate reporting within 48 hours or two work days.

III. Performance criteria

A. Monitoring frequency — Daily visual inspection of each unit; Each occurrence of a VEO being performed

Data collection procedure

Record: Time, date, and duration of each daily visual inspection of each unit subject to the state opacity standards

Record: Time, date, and duration of each occurrence when a VEO was performed on the thermal oxidizer

Each 15 second observation reading for the VEO

Record: Each occurrence of VEO

Time, date and results of corrective actions taken

Averaging period — Six minutes

APPENDIX C: MONITORING FOR FACILITY FLARES

Monitoring for Facility Flares

Monitoring approach:	*Periodic Monitoring-FL02*	*Compliance Assurance Monitoring- FL02 Periodic Monitoring-FL03, FL04, & FL05*
I. Indicator	**Assist gas to acid gas volume ratio of flare No. FL02**	**Operate flare No. FL02, FL03, FL04, & FL05 with a flame or spark present at all times when a process gas stream may be sent to it.**
A. Measurement approach	Inlet assist gas and acid gas feed volume shall be monitored with a system capable of measuring and recording the flow rate and/or the parameters utilized for flow rate calculation or estimated utilizing material balances, computer simulations, special testing and etc.	The flare tip shall be equipped either with a continuous sparking flame igniter that is monitored by an amp meter or an equivalent device Or visual observation Or with a continuously burning pilot light that is monitored with either a thermocouple or an equivalent device or by visual observation.
II. Indicator range	**Assist gas to acid gas volume ratio shall be maintained at => 1.0**	**Presence of a flame or spark at flare tip**
	A deviation is defined as anytime the actual ratio falls below 1.0.	A deviation is defined as when there was no spark or flame present at the flare tip when a process gas stream could be vented to it.
	If the accumulated hours of deviation events occurring exceeds 1% of the emergency flare operating time during a semi-annual reporting period an immediate running of an air quality modeling study that utilizes the maximum inlet mass and flow rates that occurred during this period. The maximum ratio may be modified upon receipt of Departmental approval.	A deviation triggers an immediate inspection and corrective actions that meet the requirements of 40 CFR Part 64.7(d) and reporting within 48 hours or two work days.
A QIP threshold	Not applicable	If the accumulated hours of deviation events occurring exceed 5% of the FL02 flare operating time during any quarterly reporting period, a Quality Improvement Plan (QIP) shall be developed and implemented. A QIP would not be required for the other facility flares.
III. Performance criteria		
A. Data representiveness	Each volume monitor shall be located upstream of the flare and shall consist of a single device that monitors all streams or multiple devices that monitor individual or multiple streams.	Each flame igniter or flame sensor shall be located at the flare tip and focused on the area where gas exits the flare tip.

Monitoring for Facility Flares

Monitoring approach:	*Periodic Monitoring-FL02*	*Compliance Assurance Monitoring- FL02 Periodic Monitoring-FL03, FL04, & FL05*
		Visual observations shall be made from the location that provides the best view of the flare tip and/or flare pilot lights or flare igniter.
B. Verification of operational status	Not applicable	Not applicable
C. QA/QC practices & criteria	Each volume monitor shall be maintained and calibrated in accordance with the manufacturer's specifications.	Each flame igniter or flame monitor shall be maintained and calibrated in accordance with the manufacturer's specifications, other written procedures that provide adequate assurance that the device is properly maintained and calibrated accurately or at least annually whichever is more frequent. Repairs and/or replacements shall be made immediately when non functioning or damaged parts are found. Flame igniter arc length shall not exceed 10% of arc interval and shall have an arcing frequency of no greater than once every 3 seconds.
Data collection procedure	Calculate &/or record an inlet volume that is representative of the volume entering flare.	Record time, date and duration of each incident of when no spark or flame was present at the flare tip when a process gas stream could have been sent to it.
	Record daily hours of operation.	
	Calculate & record H_2S feed rate.	Record time, date and results of each visual observation.
	Record time, date and results of each calibration.	Record time, date and results of each calibration.
	Record time, date and results of each inspection and corrective actions taken.	Record time, date and results of each inspection and corrective actions taken.
	Submit air quality modeling results to the Department within 60 days of the end of the semi-annual period.	
Averaging period	Hourly	Instantaneous

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APPENDIX D: OPACITY MONITORING FOR FACILITY FLARES

Opacity Monitoring for the Facility Flares

Monitoring approach:	*FL02, FL03 & FL05* *Periodic Monitoring*	*FL04* *Periodic Monitoring*
I. Indicator	**Opacity**	**Opacity**
A. Measurement approach	Provided a flaring event occurs for Flare No. FL02, FL03, or FL05, a daily visual emission observation of the flare shall be undertaken. Duration of each observation shall be: >= 15 minutes and <= 120 minutes Each observation shall be conducted in accordance to either: Test Method 9 of 40 CFR Part 60 Or Test Method 22 of 40 CFR Part 60	Provided a flaring event occurs at flare No. Fl04 , a daily visual emission observation of the flare shall be undertaken. Duration of each observation shall be: >= 15 minutes and <= 60 minutes Each observation shall be conducted in accordance to either: Test Method 9 of 40 CFR Part 60 Or Test Method 22 of 40 CFR Part 60
II. Indicator range	**Accumulated time that opacity is > 0% shall not exceed 5 minutes.** A deviation is defined as anytime the Accumulated time exceeds 5 minutes during any observation while utilizing either Method 9 or 22. A deviation triggers continued visible emissions observations at a frequency suitable to defining the duration of the visible emission deviation event. One observation shall be undertaken to establish the end of the visible emission deviation event.	**No 2nd 6-min. opacity average > 20%** **No 6-min. opacity average > 40%** **Or** **Accumulated time that opacity is > 0% shall not exceed 12 minutes.** A deviation is defined as anytime the observed 6-minute average opacity exceeds 20% for the 2nd time when utilizing Method 9. A deviation is defined as anytime the observed 6-minute average opacity exceeds 40% for the 1st time when utilizing Method 9. A deviation is defined as anytime the accumulated time in which visible emissions were observed exceeds 12 minutes per observation when utilizing Method 22. A deviation triggers continued visible emissions observations at a frequency suitable to defining the duration of the visible emission deviation event. One observation shall be undertaken to establish the end of the visible emission deviation event.

Opacity Monitoring for the Facility Flares

Monitoring approach:	*FL02, FL03 & FL05* *Periodic Monitoring*	*FL04* *Periodic Monitoring*
III. Performance criteria		
A. Monitoring frequency	Daily	Daily
Data collection procedure	Record: Daily Each 15 second observation reading Record: Each occurrence Time, date and results of corrective actions taken	Record: Daily Each 15 second observation reading Record: Each occurrence Time, date and results of corrective actions taken
Averaging period	15 seconds	Six minute